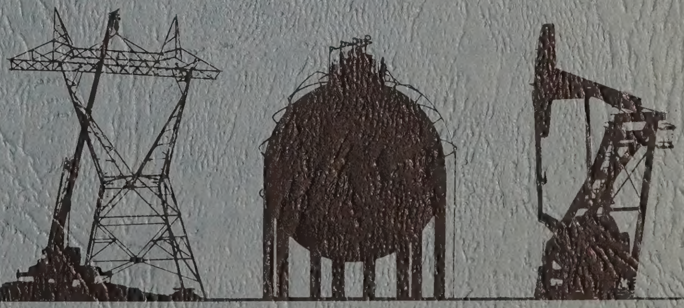
National Energy Board

CANADIAN ENERGY

Supply and Demand 1985-2005



October 1986

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Pages 178 to 184 Appendix Table A3-5

Units should read "Ratio" rather than "Percent".

Page 235 Appendix Table A4-4 Yukon, High Price Case

The numbers shown in every year for Comb. Turbines should intead be under Int. Combustion.

Page 236 Appendix Table A4-4, Northwest Territories

The last 4 numbers in the Low Price Case in 1984 should be changed to the corresponding numbers shown for the High Price Case.

Page 237 Appendix Table A4-4, British Columbia, Yukon and Northwest Territories

(i) The last four numbers in the Low Price Case in 1984 should be changed to the corresponding numbers shown for the High Price Case; and

(ii) In the High Price Case, for every year, the numbers shown for Comb. Turbines should read 172.0 (and not 214.0); and for Int. Combustion should read 269.0 (and not 227.0) except for the year 2005 which should read 297.0

Page 347 Appendix Table A7-12, Butanes Supply and Demand - Canada

The Supply Total and Potential Exports in the Low Price Case in the years 2000 to 2005 should read as follows:

	2000	2001	2002	2003	2004	20
Supply Total	9.6	8.9	8.2	7.6	7.1	6
Potential Exports	3.7	2.9	2.2	1.6	1.0	0

CANADIAN ENERGY SUPPLY AND DEMAND 1985 - 2005

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Foreword

The National Energy Board (NEB) was created by an Act of Parliament in 1959. The Board's regulatory powers under the National Energy Board Act include the licensing of the export of oil, gas and electricity, the issuance of certificates of public convenience and necessity for interprovincial and international pipelines and international power lines and the setting of just and reasonable tolls for pipelines under federal jurisdiction. The Act also requires that the Board keep under review the outlook for Canadian supply of all major energy commodities, including electricity, oil and natural gas and their by-products, and the demand for Canadian energy in Canada and abroad.

Since its inception the Board has prepared and maintained forecasts of energy supply and requirements and has from time to time published reports on them after obtaining the views of interested parties. The latest of these reports was issued in September 1984. It was prepared by Board staff without the involvement of Board members in a formal hearing process as had previously been the practice. In preparing the September 1984 report, Board staff took into account written submissions which had been submitted from interested parties in response to an open invitation made by the Board.

Since September 1984 the outlook for energy markets has changed reflecting changing perceptions of future energy prices, economic activity, and the availability of energy supplies. Government policies have also changed at both the federal and provincial levels in Canada, and in the United States, the major market for our exports of energy. In both countries, policy changes have tended to reduce the regulation of energy markets with potentially important consequences for energy supply and demand.

In light of these changes and the concomitant need to reappraise future prospects, the Board in March 1986 announced that its staff would update the September 1984 report. The Board stressed that this updating would be separate and distinct from any of the Board's regulatory proceedings.

For this report, the consultation process has been simplified, the objective being to benefit from the advice of interested parties at reduced cost to themselves and to the Board. Although anyone wishing to submit information was welcome to do so, the Board did not request formal submissions. Board staff prepared preliminary assumptions and results; consulted with provincial governments, industry and other interested parties; and in light of these consultations finalized the projections. We want to thank all those who generously gave of their time and expertise to this endeavour; their input was most useful.

This report provides detailed information on the assumptions, methodology and results of the analysis of the supply and demand for energy in Canada. The interpretations and conclusions presented are, of course, those of Board staff. Copies of this report or of a companion Summary report can be obtained by contacting the Secretary of the Board at 473 Albert Street, Ottawa, Ontario, K1A 0E5.

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Chapter 1
Introduction

There have been major developments in energy markets since the publication of the Board report "Canadian Energy Supply and Demand 1983-2005", September, 1984 (the September 1984 Report). Oil prices have declined; they fell abruptly in the first half of 1986. U.S. natural gas markets remain soft; natural gas is selling in 1986 at prices much lower than many anticipated even a year ago. There has been substantial deregulation of oil and natural gas in Canada and gas in the U.S.A. Each of these developments is potentially significant to future energy prices, economic performance and future energy demand and supply in Canada.

The massive real oil price increases which occurred between 1973 and 1980 caused sufficiently large reductions in world oil demand and increases in oil supply that the 1981 price of $ US 34 per barrel could not be sustained.

On the demand side, the industrialized oil importing countries implemented conservation and substitution programs. Energy-saving measures and technologies were introduced. The composition of Gross Domestic Product (GDP) evolved toward less fossil fuel intensive activities. In sum, the demand for oil and other energy has been responding to changes in price.

The supply of oil on world markets has been influenced by the varied cost profiles, economic interests and market behaviour of producing countries. High prices during the 1970s induced increased world supply in a growing number of countries for all forms of energy.

As a result, international oil supply management by major producing countries has become very difficult. The burden of adjustment to falling prices has been shared unevenly among producing countries with different interests and adaptability, creating difficult co-ordination and co-operation challenges for them. Oil prices fell abruptly in early 1986 to a range of $ US 10 to 16 (1986) per barrel. This experience raises major questions and uncertainties about the future behaviour of world oil prices.

Since the early 1980s there has been surplus deliverability of natural gas in the United States which developed largely as a result of the U.S. policy response to increasing oil prices and threats to security of supply in the 1970s. American policy encouraged the development of high cost domestic natural gas supply through regulated pricing, such that the blending of low priced "old" natural gas and high priced "new" gas yielded average prices significantly above those of earlier times. ("Old" gas is defined in U.S. legislation as gas discovered before 1978.) The policy had the combined effect of reducing demand and increasing supply, resulting in a deliverability surplus, the so-called "gas bubble".

Over the past decade, many industrial and utility energy consumers have installed dual fuel handling equipment, enabling them to switch between oil and natural gas on short notice, depending on relative prices. As oil prices fell in real terms between 1981 and 1986, natural gas prices eventually had to fall, failing which natural gas would lose an important share of its market. Competition grew between oil and natural gas and within the natural gas industry for market share. A market for short term natural gas contracts has emerged in which prices are now very low by historical standards, reflecting excess supply and competition for markets.

An important underlying issue in the United States is whether or not the current excess deliverability is masking a longer term shortage of domestic natural gas at "reasonable" prices.

These considerations raise questions and uncertainties about the trajectories of U.S. domestic supply, demand and prices of natural gas. These are important to Canada, because U.S. gas prices will have major effects on Canadian natural gas prices, gas development prospects and exports.

Public and industry perception of the energy problem changed with the increasing tendency toward excess supply and falling prices. Concern has been shifting from security of supply and price management to one of improving the efficiency of market mechanisms. In both Canada and the United States, governments have deregulated oil and are in the process of deregulating natural gas markets so that flexible pricing can balance supply and demand.

These policy changes are very recent and it is too early in the life of these programs to assess their impact on natural gas markets in both countries. However, the general implication is that natural gas prices should fluctuate as supply and demand conditions change.

These regulatory changes affect the way in which we project Canadian oil and natural gas prices. Rather than projecting a framework of regulated prices determined by government policy, it is now necessary to consider how the market will determine oil and natural gas prices, and the relationship between them.

The shifts in market conditions and regulatory arrangements create a climate of heightened uncertainty about the impact that current surpluses and reduced prices will have on future demand, supply and prices.

Examples of demand-related uncertainty are the effects of reduced oil and gas prices on energy conservation and efficiency of energy use. While very large oil price increases reduced demand for oil over the past decade, falling oil prices may not cause a symmetrical increase of oil demand in the future. Consumers and producers may be reluctant to increase their dependency on oil, given past experience. Permanent technical change has taken place and it may not pay to undo the conservation measures which occurred in response to increasing oil prices.

Price is not the only factor affecting demand. Technological change happens for many reasons, some being related to oil and other energy costs, others not. Technological change which moves production from a basis of fossil fuel to electricity reduces the demand for oil, quite apart from the influence of oil prices.

All else equal, reduced oil prices reduce the oil import costs of net importing countries, increasing their national incomes, overall consumption and therefore demand for energy. This factor may cause some income-related increase in oil demand. There is much uncertainty about what change these factors will engender in demand for energy in general and oil in particular.

On the supply side, there is uncertainty about the effects of reduced prices on reserves additions of oil and natural gas in non-OPEC countries. The future of non-OPEC oil and gas supply will depend upon a delicate balance between the cost of discovering and producing new reserves, the prices investors expect to see in the market place, the confidence they have in future revenue estimates, and the capital they generate or may attract to make the investments to bring on new supply. For example, if investment conditions were such that non-OPEC supply increased at a lower rate than demand, dependence on OPEC oil would increase unless competitive energy alternatives were available.

In sum, the extent and timing of OPEC's future control over supply is uncertain, yielding uncertainty about the levels at which oil prices could be sustained.

These uncertainties of demand, supply and prices make it especially difficult at present to specify a single outlook for oil and gas prices and a concomitant reference case for energy supply and demand. To do so would imply that a reference case was more likely to occur than values within a range around it, and hence that its underlying assumptions were more likely correct. We do not believe it reasonable to make this kind of statement given the circumstances discussed above.

Therefore, we have adopted an approach in this report in which we specify a plausible range for world oil prices over the outlook period, and develop two scenarios for energy supply and demand corresponding to a lower and higher projection of world oil prices. This is a different approach than that used in the September 1984 Report. At that time we focussed on a reference case and a plausible range around it.

On a world scale Canada is a relatively small producer and consumer of oil. Therefore we assume that Canada will be a price taker on the world oil market, exporting and importing oil at world market prices. We assume continuation of the current policy whereby domestic oil prices are not regulated, and there are no export taxes, import duties or other charges of equivalent effect on crude oil or most internationally traded oil products. Therefore oil prices in Canada are the same as world oil prices, adjusted for transportation and quality differentials. The price of West Texas Intermediate crude is the world oil reference price used to derive Canadian oil prices.

Several basic choices have to be made about the way in which the world oil price outlook should be constructed and interpreted. Firstly, there is a question about how to handle short-term variability. One of the few near-certainties with regard to oil prices is that they will fluctuate over time - perhaps severely. The historical record is one of cycles which have irregular timing and shape. Therefore a smooth projection will not replicate the probable year to year reality of oil price movements. Moreover, it is likely that for the most part consumers and producers react to broad protracted changes in oil prices over a period of years. We cannot develop an accurate overview of short-term price fluctuations; however these fluctuations would not materially affect the long term outlook. Therefore we do not attempt to specify the precise pattern of oil price movements over time.

Secondly, there are different ways of thinking about a plausible range for world oil prices. One is to attempt to determine extreme values, high and low, to which the price may fluctuate for a very short period of time. This approach is not very

useful because the extreme points would not last for long enough to be meaningful and the range between them would be too large.

The approach we have selected for this study is to define what may be described as lower and higher *sustainable* paths of oil prices. The factors giving rise to either a lower or a higher sustainable price path are demand growth (which in turn depends on economic variables and the efficiency of energy use), evolution and cost of non-OPEC supply, the market share falling to the middle-Eastern OPEC countries, and the consequent leverage they have to achieve price increases without substantially eroding their market share. Uncertainty about these factors means that there could be a wider band of sustainable price paths than the one we have adopted.

The definition of the lower and higher price paths does not mean that oil prices will remain on either one of these paths year after year. The oil price will most likely fluctuate above or below each of these paths in any year, but it is not possible to forecast these fluctuations. The meaning of these two scenarios is that each is a *qualitatively* different long-term view emerging from different behavioural assumptions sustaining either relatively lower or higher prices. Moreover, it is possible that the actual path could be a composite of the two projections, for example close to the low path in the earlier years, drifting up over time toward the higher path by the end of the study period.

Having established this range for world oil prices, the thrust of our study is to analyze what difference it would make to demand and supply for energy in Canada if experience validated either the higher or the lower price path.

The lower and higher price paths developed for oil have direct implications for the price paths of natural gas, given the competition for market share between these fuels - especially in the United States.

Defining the future relationship between natural gas and oil prices is particularly difficult, as it partly depends on the prospects for U.S. gas supply. Past experience can provide little guidance on this issue; American gas prices have been regulated for more than thirty years. We assume that gas prices will track oil prices because of the extent of gas:oil competition in the U.S. industrial and utility markets. If gas supply in the United States declined, at some point this could result in gas prices rising relative to oil prices. However in this event, U.S. demand for imported oil could increase, exerting upward pressure on the world oil price, tending to restore the gas: oil price relationship.

The relationship between natural gas prices and oil prices is most important to the Canadian gas industry. If oil prices were to remain very low and gas prices tracked oil prices for a prolonged period of time, there would be little incentive for Canadian producers to develop new gas supplies for export.

Because of their direct and induced effects on export revenues and import costs, different oil prices have different implications for economic growth, and economic growth affects demand for energy. Therefore a different economic growth projection has been developed for each of the low and high oil price cases.

The projected Canadian economic growth rate is higher for the low oil price case than it is for the high one. This implies that gains (losses) accruing to non-energy industries and employment from lower (higher) oil prices would outweigh the losses (gains) to the oil and gas related industries located mainly in the producing regions. The mechanism by which oil prices influence real income is that as the cost of energy falls (rises) relative to that of other goods and services, the real income available to consume them increases (decreases), causing concomitant change in demand, production and investment. The change in demand occurs with respect to both domestic consumption and foreign demand for Canadian exports. For a net energy exporter such as Canada, the change in value of energy exports counteracts this mechanism, mitigating the increase (decrease) of economic growth resulting from falling (rising) energy prices.

There are factors other than oil prices which determine economic growth; in our projections they are common to both oil price cases. Alternative assumptions for these factors could yield different economic growth rates and levels of energy demand and supply than those presented in this report. Therefore the two projections used in this report do not necessarily define the outer limits of energy demand or supply.

Over the long run, Canadian supply of oil and natural gas will depend upon the relationship among market prices for oil and gas, government taxation and royalty policies and the costs of finding and producing new supplies. As prices and income affect energy demand and supply, we use our energy price and economic growth estimates to generate demand and supply profiles for energy in Canada.

Since oil and natural gas prices are largely determined in the international marketplace, Canadian prices would not necessarily respond to imbalances between Canadian supply and demand, unless Government policy were to insulate the Canadian market from the international market. Therefore, depending upon price, there could be either excess demand for or excess supply of a particular Canadian energy resource.

For each major energy form, our report shows a supply and demand balance covering the period 1985 to 2005. A separate balance is shown for each of the low and high oil price cases. The supply profile shows what Canadian supply may be available every year, given relevant prices and physical factors, while the demand curve shows annual demand given the same prices and other determining factors. As long as the supply profile lies above the demand curve, this indicates a surplus. Where a "cross-over" occurs, Canadian supply becomes insufficient to meet demand. In the case of oil, the excess of demand over domestic supply would probably be satisfied by increased imports (see Figure 1-1).

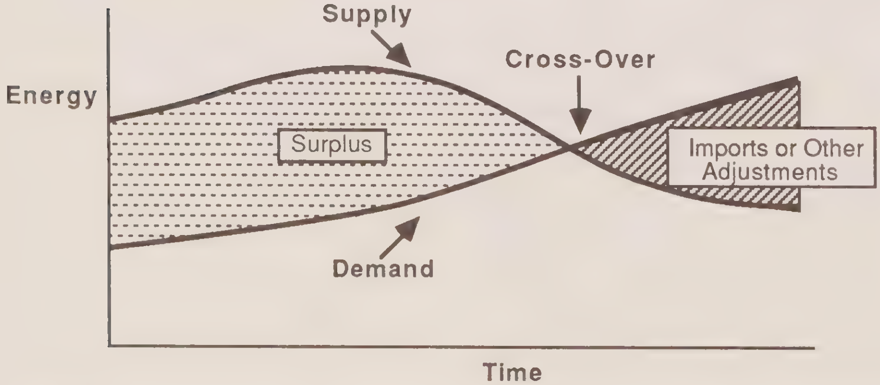
In the case of gas, this adjustment mechanism may not be so readily available because the supply and transportation of natural gas may be more restricted than that of oil due to both physical and cost considerations. This implies that a deficiency of domestic gas supply would have to be overcome by substitution of oil (perhaps involving increased oil imports), domestically generated electricity, use of coal or sufficient increase in gas prices to elicit more gas supply.

We do not expect there to be significant excess demand for electricity in Canada because the utilities build capacity in anticipation of domestic demand, recovering their investments through provincially regulated electricity rates. Surplus electricity is made available for export at prices which are acceptable to buyers and sellers and which satisfy regulatory requirements.

The demand profile outlined in this report includes staff estimates of gas, oil and electricity exports likely to flow under existing Board authorizations, and potential electricity exports not yet authorized. The latter relates to a number of prospects which some utilities have under consideration to build capacity for firm power exports. Export estimates and supply/demand balances in this report are of course independent of and without prejudice to Board consideration of future energy export or facilities applications.

Figure 1-1

Illustration of a Supply/Demand Cross-Over



Report Outline

Chapter 2 describes the energy price and economic growth assumptions underlying the ensuing demand and supply projections. Specifically, it explains the oil prices projected for the low and high oil price cases, the corresponding natural gas prices, electricity prices and the economic growth assumptions specific to each case.

Total end use energy demand is examined in Chapter 3 by consuming sector, by region of Canada and by fuel. Hydrocarbon demand for non-energy use (mainly petrochemical feedstock) is also discussed. Fuels are needed to provide end use energy. (For example, electricity generated in thermal power plants requires coal, oil, natural gas or uranium for its production.) When these requirements are added to end use demand, the result is "primary energy demand", also examined in Chapter 3.

The report then examines on an individual commodity basis the ability of domestic energy sources to satisfy projected domestic demand.

Thus, Chapter 4 examines the implications of the demand for electricity for generating capacity, electrical energy production by region, possible surpluses available for export

and primary energy used to generate electricity.

Chapter 5 discusses natural gas reserves, reserves additions and ultimate potential from conventional areas, the frontier areas' supply potential, exports and supply/demand balances.

Chapter 6 examines crude oil supply, taking into account established reserves, reserves additions from enhanced oil recovery and drilling in conventional areas, synthetic crude and bitumen, pentanes plus and supply from frontier areas. Exports and imports are examined along with the implications of domestic demand for refinery feedstock requirements. Supply and demand balances are examined for light and heavy crude. The chapter concludes with comments on the implications for oil pipelines of projected oil supply and demand .

Chapter 7 examines the prospects for supply and demand of natural gas liquids, taking into account gas plants, refinery production, use of liquids in miscible flood projects and as fuels used in the production of synthetic crude oil, and supply/-demand balances.

Chapter 8 discusses coal resources, reserves, production, exports and imports.

Chapter 9 draws together the sources and uses of primary energy, incorporating the primary demand, energy export and energy production projections of the preceding chapters. The chapter also provides an international perspective, showing Canada's energy use compared with that of other countries.

Chapter 10 sets out our major conclusions.

Appendix 1 provides abbreviations of names and terms, conversion factors and definitions.

Appendices 2 to 8 provide supporting data for Chapters 2 to 8 respectively.

Chapter 2
Energy Pricing and Macroeconomic Assumptions

Changes in energy demand and supply will occur in response to changes in energy prices, economic activity, structural features of the economy and physical characteristics of energy supply. The purpose of this chapter is to lay out our energy price and macroeconomic growth assumptions, and to explain the factors underlying them.

The pricing assumptions are central to the whole overview because the cost of energy affects total energy demand and supply. Changes in relative prices between energy forms affect the composition of energy demand between oil, gas, electricity and other sources of energy. Prices - actual and expected - are a critical determinant of energy supply through their influence on investment in the energy supply industries.

Because Canadian energy markets are very much exposed to international developments, the outlook for Canadian oil and natural gas prices depends mainly on that for world oil prices and U.S. natural gas prices. We develop our outlook for Canadian oil and gas prices beginning with consideration of world oil prices and U.S. natural gas prices.

Electricity prices in Canada are largely determined by provincial regulation, which is generally based on the utilities' cost of service. Utility tariffs are structured so that the prices charged to each consumer category collectively yield total revenue approximating the cost of service. Therefore we project electricity prices based on an assessment of how cost of service and utility tariff structures will change over time.

Our discussion of oil, gas and electricity price assumptions appears in Sections 2.1, 2.2 and 2.3 respectively.

Assumptions about the structure and growth of economic activity are particularly important to energy demand projections because demand for energy is derived from the production and use of goods and services. Energy development, in turn, influences regional economic growth. Structural features of the economy include developments in demographic and lifestyle factors, the mix of goods and services production and the kinds of goods produced, and changes in production techniques. Structural factors influence energy efficiency (energy input per unit of output) and the share of different energy sources in total energy use (for example the relative use of fossil fuel and electricity in heavy industry). Our assumptions with respect to economic growth and its distribution between activities and regions are discussed in Section 2.4.

2.1 World Oil Price Outlook

The evolution of world oil prices will be determined by a number of factors, including:

- changes in world demand for oil;
- price and availability of competing fuels (a factor influencing demand for oil);
- changes in world supply of oil, its geographic concentration and marginal supply cost; and
- the extent to which the international supply of oil can be coordinated to control volume and therefore price on world markets.

Each of these major factors is related to the others, and each may be seen as the top of a pyramid, under which lie numerous additional determining factors. These factors include technical change, growth of income and output, current oil prices and consumer attitudes, all of which influence demand for oil. Current and expected oil prices and industry cash flow influence the amount and location of reserves additions and economic, technical and geological factors influence incremental supply costs. The foregoing factors and political circumstances will influence the potential effectiveness of international market co-ordination.

Recent experience seems to have fundamentally altered perceptions about the feasible range of oil price behaviour. The price collapse of 1986 was the outcome of a market situation in which it was increasingly difficult for the OPEC countries to influence oil supply and price since oil prices peaked between 1980 and 1981.

Table 2-1 shows in a nutshell what happened. Nominal oil prices increased from \$ US 21 per barrel in 1979 to \$ US 34 per barrel or more in 1980 and 1981. Measured in 1985 dollars (to compare real value on the U.S. market), the 1980 price was equivalent to \$ US 44 per barrel; by 1985 the oil price had declined to about \$ US 28 per barrel, a real drop of 36 percent. This occurred mainly because world oil productive capacity exceeded demand.

Between 1979 and 1985 there was a large drop of 10 million barrels per day in world production mainly due to a drop in the demand of OECD countries. (In OECD countries the use of oil per unit of Gross National Product fell by about 30 percent between 1973 and 1985.) While demand was declining, non-OPEC non-centrally planned economies' producers increased their share of world production from 28 percent in 1979 to 42 percent in 1985; in response to the increasing prices of

Table 2-1

Petroleum Supply, Demand and Price in 1979 and 1985[a]

	1979	1985
	(Millions of barrels per day)	
World Production	63	53
OECD Demand	42	34
OPEC Supply	31	16
Arab OPEC Supply	21	9
Non-Arab OPEC Supply	10	7
Non-OPEC non-CPE Supply[b]	18	23
Centrally Planned Economies(CPE) Supply	14	14
	(Percent)	
OECD Demand Relative to Non-CPE Supply	86	88
OPEC Market Share [c]	49	30
Arab OPEC Market Share [c]	34	17
Non-Arab OPEC Market Share [c]	16	13
Non-OPEC non-CPE Market Share [c]	28	42
CPE Demand Relative to CPE Supply	89	89
	1980	1985
	(Dollars)	
Oil price $ US Nominal [d]	34	28
Oil Price $ US 1985 [e]	44	28

Note: All numbers on this table have been rounded.
[a] Supply and demand data exclude natural gas liquids.
[b] CPE countries include China, Eastern Europe and U.S.S.R.
[c] "Market Share" means group share of world production.
[d] Approximate average refinery acquisition cost.
[e] 1980 value adjusted using U.S. GNE deflator.

the 1970s they developed productive capacity which was feasible to operate at the prevailing oil prices. As a result, OPEC output dropped from 31 million barrels per day in 1979 to 16 million barrels per day in 1985, a decline in its share of world production from 49 percent in 1979 to 30 percent in 1985.

The Arab OPEC group (especially Saudi Arabia) absorbed most of the impact of this declining market share. While the Arab OPEC share of the world market declined by 17 percentage points between 1979 and 1985, that of the non-Arab OPEC group declined by only 3 percentage points.

Given falling demand, excess supply and many producers competing for a shrinking market, prices should have decreased, and they did. This decline was less than it might have been because Saudi Arabia acted as a "swing producer". It withheld its own supply from the market in order to moderate price adjustment, but was unsuccessful in encouraging other producers to do the same. By the end of 1985 Saudi output had declined to about 2.5 million barrels per day (compared with its OPEC quota of 4.5 and its productive capacity of 10 million barrels per day). Saudi Arabia decided that its solitary role as swing producer was untenable - it could no longer support a high world oil price at its own expense - so it increased supply and oil prices fell abruptly in early 1986 to a range of $ US 10 to 16 per barrel.

OPEC's supply management became difficult in the face of falling volumes and prices for a number of reasons.

- Non-OPEC supply increased because high prices induced major investments in exploration and development in a number of non-OPEC countries. Once developed, for most of these reserves, the marginal production cost is well below recent oil prices. The new suppliers have an interest in producing their reserves in order to recover their investments, to reduce their dependence on external supply and in some cases to earn badly needed foreign exchange by oil import replacement and export marketing.
- Within the OPEC group, non-Arab producers have production interests similar to those of the non-OPEC producers.
- Within the Arab OPEC group, given differences between countries in the size of their reserves and annual productive capacity, there appears to be different perspectives on supply and pricing strategy. Countries with smaller reserves or lower productive capacity and high revenue needs have an immediate interest in maximizing prices, while maintaining their output. Small changes in their individual outputs would not have a major effect on world oil prices. Countries with much larger reserves, high productive capacity and lower revenue needs have both more short term flexibility to

absorb price and volume fluctuations, and an interest in maximizing their *longer-term* market share and unit revenues. One way of doing so is to drive high cost volumes off the market by increasing their production, thereby causing world oil prices to fall.

It is far from clear how all of these divergent interests will be co-ordinated to develop some degree of producer agreement on supply and pricing strategy over time.

The market experience of the past few years and the apparent difficulties of cohesive supply management lend support to a lower band of probable oil prices than most observers considered likely in the earlier 1980s.

As we explained in Chapter 1, given the uncertainty about the many factors influencing world oil prices, it is appropriate to develop two price cases, one reflecting a combination of factors conducive to lower prices and the other to higher prices.

The following assumptions are consistent with our lower oil price outlook.

- Excess supply and flat demand in 1986 will at best allow for a weak OPEC agreement on export quotas for each member; therefore prices will remain relatively low for the rest of the year, yielding a 1986 average price of about $ US 14 per barrel.
- Moderate real economic growth occurs in major consuming countries over the outlook period, but there is a low degree of responsiveness in demand for oil; low prices and increasing incomes do not lure consumers back to considerably increased oil dependence for fear of future price effects.
- At prices around $ US 18 (1986) per barrel, there continues to be economic incentive to implement additional conservation measures, constraining both oil demand growth and the scope for sustained price increases above about $ US 18 per barrel (1986).
- With low demand growth, non-OPEC supply continues to satisfy over half of international demand, it being assumed in this scenario that sufficient non-OPEC supplies of oil, gas or alternative energy could be made available as needed over the long-term at oil equivalent prices of up to $ US 18 (1986) per barrel.
- With relatively flat demand, weak prices and competitive energy supply alternatives, OPEC countries are unable to exercise much discipline over supply. Price increases are constrained by market forces. If producers tried to increase cash flow by increasing volume beyond the market share available at the going price they would depress prices. Under the circumstances, appropriate quota balancing within the OPEC group is not easily manageable.

The following assumptions are consistent with the higher oil price outlook.

- Low short-term oil prices stimulate economic growth in major consuming countries. Income responsiveness of demand for oil is higher than in the low price case. As oil prices increase the economic growth stimulus of lower prices is dampened, but demand for oil remains relatively strong in response to the economic growth which does occur.
- Non-OPEC supplies of oil, gas and alternative energy are more expensive and less abundant than presumed in the low price case. Furthermore, they dwindle more quickly than under the low price case due to investor pessimism and financing problems created by low prices in the mid-to-late 1980s.
- American natural gas prices increase as the U.S. gas deliverability surplus is worked off and new reserves become available, but at increasing marginal cost.
- Increasing demand, falling non-OPEC supply in the late 1980s/early 1990s and the higher cost of alternative energy provide a higher share of the world oil market to OPEC and more room for OPEC to co-ordinate markets and influence prices.

We have capped the price increase at $ US 27 (1986) per barrel in the high price case largely because around this price - about $4.70 per gigajoule - energy resources other than OPEC oil should be available, constraining OPEC's ability to *sustain* price levels much beyond this range.

Table 2-2 shows our world oil price projections for the low and high oil price cases.

Figure 2-1 compares this oil price outlook with historical experience and the projections made in the September 1984 Report. Figure 2-2 shows other recent oil price outlooks prepared by major private and governmental forecasting groups. Most of them fall within our range of projected oil prices.

In this report, the Canadian crude oil price is referenced directly to the world oil price projections of Table 2-2. The domestic value of crude oil

Figure 2-1
World Oil Prices

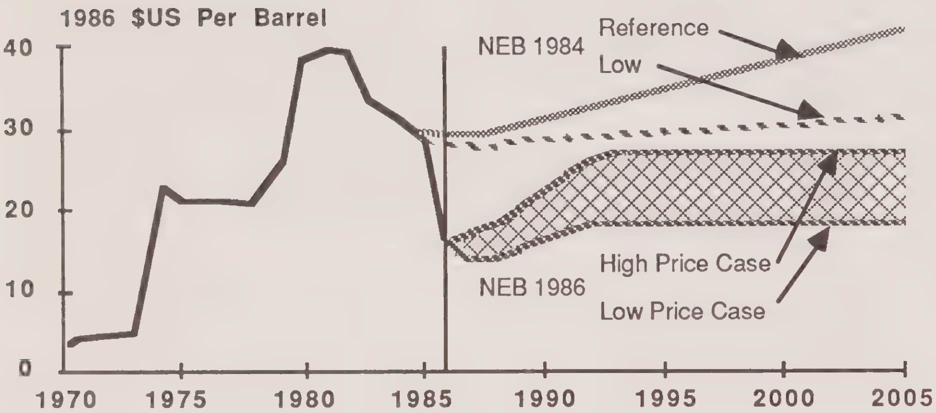


Figure 2-2
Comparison of World Oil Price Outlooks

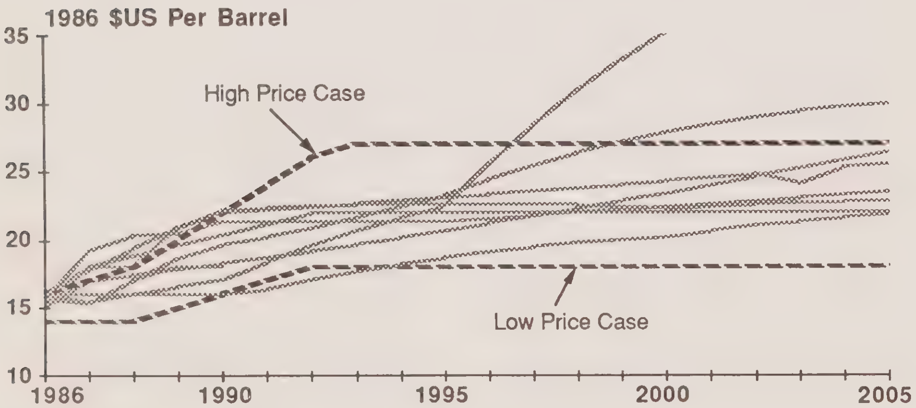


Table 2-2

World Oil Price Outlook

West Texas Intermediate Crude at Chicago

	Low Oil Price Case	High Oil Price Case
	($ US 1986 per barrel)	
1986	14	16
1987	14	17
1990	16	22
1995	18	27
2005	18	27
	(Average annual growth rates - percent)	
1986-87	0	6.3
1987-90	4.6	9.0
1990-95	2.4	4.2
1995-2005	0	0

Note: All numbers on this table have been rounded.

Source: Appendix Table A2-1

at Edmonton is the price of West Texas Intermediate crude oil at Chicago less the sum of U.S. import duty and transportation costs from Edmonton to Chicago. To derive Canadian product prices we add to the value of crude oil at Edmonton the sum of transportation costs of crude oil from Edmonton to the refineries, current refining costs and current domestic taxes.[1] Figure 2-3 shows an example of retail product prices.

2.2 Natural Gas Prices

We mentioned in Chapter 1 that policy changes are being implemented in both Canada and the U.S. to deregulate natural gas prices. They are also intended to stimulate market competition among producers by facilitating their direct access to end users. These changes necessitate developing a framework within which to determine future gas price formation in a competitive market. We also mentioned that it was reasonable to expect American natural gas prices to be competitive with oil prices.

The framework we have adopted derives from two propositions:

The first is that, but for transportation cost differentials, Canadian and U.S. gas prices should be similar. We are

1. All crude oil supplies to the Atlantic region are imported. Therefore the Atlantic region crude oil price is based on the average cost of crude oil imports. Refining costs and local taxes are added to derive product prices.

assuming that in both countries, energy policy objectives are to have flexible and competitive markets and prices. There are strong linkages between Canadian and U.S. gas markets. Canada exports over 30 percent of its gas production to the U.S. and the U.S. permits gas exports to Canada. Established Canadian regulatory policy requires that Americans pay no less for Canadian gas than do Canadians. Canadian and American firms compete in similar petrochemical products for which gas feedstock is a high proportion of product cost. For all of these reasons, we judge it reasonable to assume that the U.S. market will be the gas price leader and U.S. gas prices will be quickly transmitted to Canada by a combination of competitive and regulatory pressures. For example, if Canadian gas prices exceeded those in the U.S., Canadian gas and petrochemicals could lose markets, and there would be policy obstacles to exporting gas at prices below what Canadians pay for comparable service. These factors would tend to bring Canadian and American wholesale gas prices to equality.

Thus the key to determining the time profile for gas prices in Canada is the profile of natural gas prices in the United States.

The second proposition underlying our framework of natural gas price formation is that natural gas prices in the U.S. will essentially track the price for heavy fuel oil.

This proposition in turn derives from an assessment of the way in which energy market competition evolves. There are alternative ways in which this competition may occur, and natural gas prices will be different depending on what specific kind of competition develops. The main issues are:

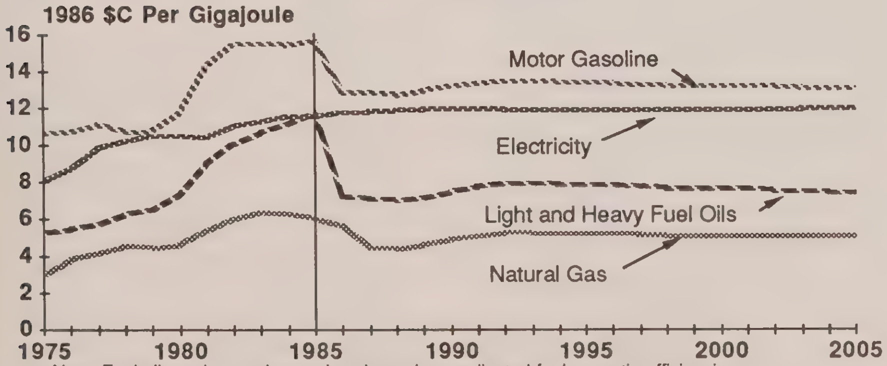
- whether or not different categories of consumers will pay different wholesale prices for natural gas as a commodity - that is, price differences beyond those justified by transportation cost differences resulting from differing distances from the supply source or differing pipeline capacity utilization; and,
- whether natural gas prices are likely to track oil prices over the period of our analysis.

The reason why there may be scope for differential gas commodity pricing between categories of consumers is that, on the whole, residential and small commercial or industrial consumers (the "core market") have more expensive alternatives and less supply switching flexibility than do the major industry and utility users. For the core market, energy alternatives to natural gas are generally light fuel oil or electricity, both of which are costlier than heavy fuel oil. For major industrial and utility users, the main alternative to natural gas is heavy fuel oil and many of them are equipped to switch rapidly between natural gas and heavy fuel oil, depending on which is cheaper. Generally, core market consumers do not have the equipment on hand to rapidly switch between gas, oil and electricity.

Because the value of gas is higher to the core market than it is to the major industry/utility market, it would be tempting for suppliers to differentiate the price of gas between these markets, charging higher prices to the core market and lower ones to the major industry/utility market. The question is whether in practice they would be able to do so. They would not if there were sufficient competition between suppliers (including producers, pipelines and distribution networks) or, in lieu of sufficient competition, if selective regulation occurred to prevent those segments of the supply chain which had a degree of monopoly power from practicing price dif-

Figure 2-3

Average Retail Energy Prices, Canada
Low Price Case



Note: Fuel oils and natural gas prices have been adjusted for burner tip efficiencies.

Source: Appendix Table A3-8

ferentiation. Price differentiation is more likely to occur when local distribution utilities have no incentive to economize on gas acquisition costs, when they have little flexibility to alter their supply arrangements with pipeline companies and when there is minimal risk that their customers will by-pass them to obtain gas directly from suppliers. Price differentiation is less likely to occur under circumstances opposite to the ones just described.

In a "price differentiation" scenario the core market would pay gas prices related to light fuel oil, and the major industry/utility market would pay prices related to heavy fuel oil.

The gas price which emerges from a "no differentiation" scenario is one in which all consumers including distribution companies serving the core market pay gas prices directly related to the cost of heavy fuel oil. Gas producers and pipelines compete for the major industry/utility market by delivering gas at burner tip prices competitive with the price of heavy fuel oil. (In fact, very large volumes of gas are now subject to this kind of competitive pricing in the U.S.).

Since it is very early in the life of the new regulatory arrangements in both Canada and the U.S., it is hard to foretell which of these scenarios will come to pass. The most likely scenario for the near future may be an amalgam of both situations. Because the U.S. has a much larger gas market with more scope for producer and pipeline competition than does Canada, it is conceivable that the U.S. market would tend more toward the "no differentiation" situation than would Canada's. However, in both countries it is likely that regulatory effort will be required to achieve "no differentiation".

Since it is the intent of government policy in both countries to have competitive gas markets, and since one result of competition is to have uniform prices for the same product to all users in the same place, we are adopting the "no differentiation" scenario as our working hypothesis for this report. We recognize that it is a simplification or approximation of reality and that it yields lower average gas prices than would the "differentiation" scenario.

An important implication of this scenario is that if or when the cost of supplying natural gas exceeded the price of heavy fuel oil gas supplies would diminish and gas prices would tend to increase.

Industrial users would respond by switching to heavy fuel oil. By this means demand for natural gas would decline along with its supply, maintaining supply-demand balance. At some point the switching ability of industrial users would be exhausted. When this happened the market could adjust in several ways. Natural gas prices could increase relative to oil prices, eliciting increased American or Canadian supply and dampening domestic demand until supply and demand balanced.

Alternatively, a major tightening of the U.S. gas market could eventually generate a large enough increase in American demand for imported oil to raise the world oil price. This would facilitate a corresponding increase in the price of gas, rationing demand and eliciting more supply from U.S. resources, Canada or other countries.

Our approach is to keep natural gas and heavy fuel oil prices equal over our outlook period. However, many analysts of U.S. gas markets suggest that U.S. domestic gas supplies will decline relative to demand in the next decade; hence it is entirely possible that U.S. gas prices could increase at a faster rate than would oil prices. If this were true, the natural gas price projections used in this report would understate, perhaps considerably, future price levels. As a result they would also appreciably understate Canadian gas supply and future opportunities for Canadian gas exports.

Assuming the "no differentiation" pricing scenario and assuming that U.S. gas prices do not increase at a faster rate than does the price of heavy fuel oil, the wholesale commodity price of natural gas in Canada is related directly to the international price of heavy fuel oil. Gas prices to end users will differ only in respect of cost differences arising from differing costs of transportation and distribution.

Given this approach to natural gas price determination, Canadian natural gas prices are developed in the following way.

- Measured on a heat-equivalent basis, and assuming effective international market competition with no domestic price differentiation, the prices of American and Canadian heavy fuel oil and natural gas will all be similar when adjusted for quality and transportation differentials.
- We assume that on average, over time, heavy fuel oil will be priced at about 90 percent of West Texas Intermediate crude. (In the past, heavy fuel oil has ranged from 75 percent to near parity with crude oil, depending upon supply and demand conditions.) The 90 percent assumption reflects an expectation that with the refinery flexibility which now exists, there should not be sus-

tained imbalance of supply and demand for heavy fuel oil.

- The price of gas to industrial users will be 100 percent of the heavy fuel oil price on a heat-equivalent basis at the industrial burner tip.
- Gas prices paid by residential and commercial users are derived by subtracting the industrial distribution charge from the industrial retail price and adding appropriate distribution charges. (These charges exceed industrial distribution charges because of lower load factors and higher delivery and administrative costs to residential and commercial users).

Table 2-3

Projections of Ontario Wholesale and Alberta Border Natural Gas Prices

	Low Oil Price Case	High Oil Price Case
	($C 1986 per gigajoule)	
Ontario Average Wholesale Price		
1986	3.52	3.60
1987	2.43	3.02
1995	3.10	4.67
2005	3.10	4.67
Price at the Alberta Border		
1986	2.58	2.65
1987	1.38	1.98
1995	2.06	3.63
2005	2.06	3.63

These calculations are done for both oil price cases. Examples of resulting natural gas prices are given for Ontario and the Alberta border in Table 2-3. Although the "Alberta Border Price" (defined as the city-gate wholesale price minus transportation to Alberta) ceases to have any regulatory meaning on November 1, 1986, the Alberta border is a useful reference point for examining gas and transportation costs by region.

The ratio of Alberta border prices to Ontario wholesale prices is not uniform over time, because transportation costs are assumed to remain constant in real terms over the whole projection period, while the gas price increases in real terms between 1987 and 1992 or 1993 after which it remains constant.

We emphasize that our natural gas price projections assume that:

- in both oil price cases U.S. natural gas supply and users' fuel-switching capability will be sufficient to ensure that gas prices will not exceed heavy fuel oil prices; and
- prices are determined in both Canada and the United States on the basis of no price differentiation between consumers other than for transportation and distribution cost differences between different service requirements.

With these assumptions, our natural gas prices are in the range of 30 percent (Ontario) and 50 percent (Alberta) below what they might be had we assumed price differentiation between different categories of Canadian consumers

2.3 Electricity Prices

Over 70 percent of operative electrical capacity in Canada is hydro and nuclear, for which capital costs are high and operating costs are very low. Therefore a high proportion of electricity prices in Canada consists of capital costs (interest and depreciation) and a large part of the wholesale electricity price is determined by the relationship between interest and depreciation charges on the one hand and amounts of energy produced on the other. The higher are these charges relative to the volume produced, the higher the price per kilowatt hour. Examples of situations conducive to relatively higher prices are surplus capacity relative to market and reserve requirements, or large scale plant additions which inherently yield growth in capacity exceeding growth in sales over their initial years of production. As surplus is reduced by growing sales, all else equal, unit cost decreases.

At present there is excess generation capacity in most Canadian power systems, and construction programs to meet domestic needs have been phased down. As sales grow, it is likely that the capital cost per kilowatt hour of electricity will decline slightly over the next few years. Later in the outlook period most systems will need new generating plant. Over the whole period, the real book value of existing plant will be eroded by depreciation and inflation, but new plant will be phased in, often at higher real cost per kilowatt. All else equal, this could imply some scope for real price declines in the near term and increases in the longer term. However, there is a tradition of gradualism in the electrical utility industry in adjusting rates to changing circumstances. Taking all of these factors into account, the utility industry generally expects, and we consider it appropriate to assume, that elec-

tricity prices will remain roughly stable in real terms over the outlook period.

2.4 Macroeconomic and Structural Determinants of Energy Use in Canada

Demand for energy resources arises not because these resources are desirable in their own right, but because they provide the heat, light and motive power enabling us to produce and use goods and services. Energy resources are also used as chemical inputs in the production of petrochemical products such as plastics, synthetic fabrics and a great many agricultural and industrial chemicals. Since economic growth and the structure of production and consumption determine the quantities of goods and services which will be produced and consumed, it follows that these factors will heavily influence the amounts of energy resources required. Therefore, to estimate demand for energy in Canada over the next twenty years, it is first necessary to estimate what economic growth and structural change may occur. We can then assess their impact on the demand for energy-using equipment and the corresponding quantities of energy resources which are required.

In this section we identify the most important aspects of economic growth and structural change which determine energy demand, and we explain how they may develop over the outlook period. We outline some major aspects of Canadian economic performance over the past fifteen years; we then set out our views on potential output growth,[1] discuss the factors underlying our national and regional projections of economic growth for the low and high oil price cases, and state our growth projections.

Between 1970 and 1985 Canada's real output[2] grew at an annual average rate of 3.9 percent. This average masks the significant variation of growth rates which occurred over the period. Between 1970 and 1974 the economy grew at an average rate of 6 percent per year and slowed to a rate of 2.8 percent per year between 1974 and 1980. As a result of the 1982 recession real output in that year was below the 1980 level, but growth averaged 3.9 percent per year between 1982 and 1985.

This variation was heavily influenced by international economic conditions and events largely beyond Canada's control. The growth of most industrialized countries slowed considerably over the period of the major oil price increases between 1974 and 1980, though oil price escalation was not the only factor influencing economic performance. The recession of 1982 engulfed many countries, but Canada more severely than others. Likewise the recovery since 1982 is closely associated with that of the international economy, especially that in the United States.

Canada's economic prospects are intimately linked with those of her major trading partners because her international trade is large relative to her Gross National Product (GNP) (the values of exports and imports of goods and services were each about 32 percent of current dollar GNP in 1985) and capital movements in and out of Canada are unrestricted.

Energy production and trade are also significant to Canadian economic performance. Over the period 1971 to 1985 energy production accounted for between 5 and 10 percent of current dollar output. Between 1974 and 1985 energy exports averaged between about 13 and 16 percent of total merchandise exports. Over the same period energy imports fluctuated between about 6 and 12 percent of total merchandise imports, varying mainly because of fluctuations in the value of oil imports.

Potential Growth

The potential growth of the Canadian economy depends primarily on the rate of growth of the labour force and productivity. The economy will not necessarily grow at the potential rate because a number of factors influence whether existing capacity to produce is in fact used.

It is difficult to estimate the potential future growth of the economy; many uncertainties surround future growth of the labour force and productivity.

The rate of growth of the labour force depends essentially on the rate of growth of the population and the extent to which the population of working age participates in the labour force. Between 1964 and 1974 population growth averaged about 1.5 percent per year. Between 1980 and 1985 it averaged 1.1 per year. Net immigration has fluctuated between 40 000 to 100 000 per year between 1980 and 1985.

In our projections, we assume that population growth will continue on a downward trend over the projection horizon. This reflects the view that

1. Potential output measures what the economy could produce on a sustainable basis using available productive resources.

2. All analyses are based on 1971 dollar measures. Data for 1985 in this section and in Chapter 3 are estimates, as the study was completed before 1985 values were available.

the total fertility rate will stay significantly below the replacement level of 2.1 children per female of child-bearing age, and that net immigration will average between 75 000 and 95 000 persons per year over the projection period. As a result, Canada's population by the year 2005 is projected to attain a level of about 30 million, an increase of about five million over the present level.

Between 1970 and 1985 the civilian labour force as a percentage of population grew from about 40 percent to 50 percent. Two driving forces behind the strong growth experienced by the labour force in recent years have been the coming to working age of people born during the post-war baby boom and the dramatic increase in the number of women seeking jobs outside the household. Most analyses concerning labour force participation rates project continuing increases in the participation of women in labour markets, though at a slower pace than in recent years. This, combined with modest increases in male participation rates, suggests that in the future we are likely to see more moderate growth in the aggregate participation rate than has occurred in the past.

Slower growth in population, combined with moderate increases in the total participation rate, results in labour force growth averaging just under 2 percent per year from 1985 to 1990 and 1.2 percent per year between 1990 and 2005.

Productivity gains are the major sources of long run increases in real income and living standards for any country. Broadly speaking, productivity is a ratio of aggregate output to aggregate input. It is a summary measure of our economic ability to turn resources of all kinds into output of goods and services.

The achievement of productivity gains depends on many factors of which technological change, the nature of the stock of capital equipment and the skills and adaptability of the labour force are critical. The exact relationships between research and development expenditure, technical change and productivity for the economy as a whole are not well understood. Though apparently a simple concept, productivity is in fact difficult to define and measure. It is therefore difficult to assess the prospects for the rate of productivity growth.

For the economy as a whole, output per employee grew by almost 3 percent per year between 1960 and 1972. Most of these gains were concentrated in manufacturing, mining, utilities and transportation; less improvement occurred in most of the service industries. Between 1973 and 1982 productivity growth was very low - about 0.2 percent per year.

Though the productivity slowdown of the 1970s has been extensively studied, there is little agreement about its causes or implications for the future; however, the most prominent factors appear to have been shifts in the relative importance of industries having different rates of output per worker, and a general cyclical decline in output growth, including capital investment. No specific factors have been identified as major causes of a long run productivity slowdown.

Recent productivity gains have been strong relative to the experience of the late 1970s. Canada's productivity gain from 1983 to late 1985 has averaged about 2.5 percent per year, a higher rate of increase than experienced in previous recoveries from recession.

It remains unclear, however, whether recent productivity growth portends a resumption of higher long-run growth than Canada experienced between 1973 and 1980. In common with a number of analysts, we are assuming that future productivity gains will be higher than those of much of the past decade, but they will not regain the high rates of the 1960s.

In our two macroeconomic projections we incorporate an average annual growth rate of productivity of about 1 percent per year. This compares with projections of about 1.2, 0.8 and 1.2 percent per year used by Data Resources of Canada[1], Informetrica Limited[2] and the Institute for Policy Analysis of the Unversity of Toronto[3] respectively. Our projection implies that the most recent experience is not sustainable over the long term.

These considerations about labour force and productivity growth indicate that over the outlook period the average rate of potential output growth will be of the order of 2 to 3 percent per year. This assumes a "full employment" level of unemployment appreciably below the current level of about 10 percent. As long as the unemployment rate is above the "full employment" level, the growth of the economy can exceed the potential output growth estimate.

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1. *Canadian Review,* Spring 1986
2. *The Canadian Economy to 2005, Post-Workshop I-86,* August 1986
3. *National Projections Through 1995,* June 1986.

Factors Affecting Probable Growth

At the present time, the Canadian economy is operating below its potential capacity for production, given the large reserve of unemployed labour.

Although the recovery from the 1982 recession has been significant in Canada, and more substantial in the United States, there is considerable uncertainty as to whether the improvement in Canadian economic activity will continue to be rapid enough over the medium term to close the gap between potential and actual production.

A range of external and domestic factors will determine actual growth of the Canadian economy over the outlook period. The main international influences are the growth rate of the U.S. economy, the international competitiveness of the Canadian economy, the exchange rate between the Canadian dollar and other currencies, world oil prices and other commodity prices. The main domestic influences are domestic demand, of which gross fixed capital formation (private and public sector investment) is a volatile component, and governmental monetary and fiscal policies.

The major issues for economic management in most of the industrialized world concern unemployment, inflation, government deficits, international debt and currency realignments. American policy to deal with these issues is most immediately relevant to Canada.

The United States is facing economic problems on both the domestic and international fronts. There is a threat of increasing unemployment due to the recent levelling off of consumer demand and investment growth from the rates achieved between 1983 and 1985. At the same time American law and policy tend to constrain the size of the federal budget deficit and U.S. authorities are concerned about the increasing international current account deficit.

The American policy response is to try to reduce the federal deficit, offsetting its contractionary impact on demand by lowering real interest rates to stimulate investment and consumer demand. The U.S. is also encouraging other countries to stimulate their economies and further open their markets so that demand for American exports will increase. At the same time, there is growing pressure for trade protectionism in the United States which the Administration is resisting, not always successfully. Major European countries and Japan are reluctant to stimulate demand for fear of its effects on inflation and their payments balances; they attribute the U.S. trade problem mainly to an over valued U.S. dollar.

There is little doubt that the international debt situation - particularly of certain industrializing developing countries - is a constraint on the growth of the industrialized countries. A substantial fraction of incremental demand for developed country exports has in the past come from the developing countries, which have recently been forced to contract their economies in order to manage their debt service payments.

Canada will face the effects of this uncertain outlook for growth of the U.S. economy and international trade. Domestically, there is growing evidence that the recovery from the 1982 recession is levelling off. Notwithstanding that the unemployment rate remains close to 10 percent, there is great concern both about federal and provincial government deficits, and about the possible inflationary effect of allowing the Canadian dollar to depreciate relative to the U.S. dollar.

Gross fixed capital formation in Canada declined in 1982 and 1983, showed little change in 1984, but grew in 1985. Canada's overall growth of industrial labour productivity has been trailing that of some of our major trading partners (though the data supporting these international comparisons must be interpreted very cautiously). Considering the uncertain international economic environment and the policy constraints on adopting stimulative monetary and fiscal policies, it seems prudent to assume that Canadian economic growth will be moderate over the next few years, in the range of its long term potential growth rate, but not fast enough to absorb all of its near term excess productive capacity.

Energy prices will also have a noticeable effect on Canada's economic growth. Recently, with the decline in world oil prices, analysts have been assessing the impact of this price decline on economic activity relative to an outlook with higher prices. These analyses consider the impact of the change in oil prices on both the external environment and the domestic economy. Other factors such as fiscal and monetary policy or demography are usually left unchanged, or neutral. In general, these analyses have concluded that for most industrialized, oil importing countries, including the United States, a decline in the world oil price will improve economic growth.

Since Canada is a net oil and energy exporter, the impact of a decline in oil prices is less clear. The national impact will reflect the sum of regional impacts. For provinces heavily dependent on oil and gas

production, a lower oil price will reduce incomes, delay resource development and generally dampen economic prospects relative to a higher oil price scenario. However, for central Canada, where manufacturing is a more important determinant of growth, economic prospects should improve for two reasons: higher activity in the United States will increase demand for imports from Canada and lower energy prices will reduce costs and prices, increasing incomes and raising domestic demand for goods and services.

Since much of the energy sector's capital equipment comes from central Canada, reduced activity in the energy sector has a negative impact on central Canada's economic activity. Though the magnitude of each of these responses is not well-defined, the consensus of most Canadian analysts is that aggregate economic activity in Canada will, other things equal, increase as a result of lower energy prices because gains in central Canada will outweigh losses in energy producing areas.

There is considerable variation in the outlooks for the regions of Canada.

- In the Atlantic region, there is not a substantial difference in total output growth between the low and high price cases, as the absence of Hibernia development in the low price case is offset by improved economic activity in Nova Scotia and New Brunswick. Thus, while provincial prospects within the region will differ between the two cases, total regional growth is similar.
- Quebec and Ontario are expected to benefit from lower oil and gas prices. Higher domestic and export demands for these provinces' goods and services leads to stronger growth in the low price case.
- For the Prairies, the major difference shows in the mid-to-late 1980s, as resource industry activity slows in the low price case. Although there is some recovery after 1990, by 2005 the economy in that region is still smaller under the low price case than in the high one.
- Though British Columbia has an important energy sector, its other resources - particularly forest products - play a more important role in its growth. This province is also very sensitive to U.S. economic activity since it relies heavily on the export market as an outlet for its production. As a result, we have stronger growth under the low price case, reflecting increased export opportunities and higher incomes within the province, than would be the case with higher oil prices.

In developing these macroeconomic outlooks for our two oil price cases we have chosen to focus on the differences in the outlook resulting from the differing oil prices, rather than on developing high or low growth scenarios, in which many other factors would differ between the two cases. We have adopted the view that economic growth will be higher under the low oil price track than under the high one. These outlooks are not the only conceivable views of high or low growth paths, as alternative assumptions for major external influences other than oil prices could be combined to yield growth rates which are significantly higher or lower than those we have postulated for the low and high oil price cases.

Table 2-4 shows our national and regional growth projections, based on the determining factors and assumptions discussed above. It also shows the growth rates between 1975 and 1984.

For Canada, in both oil price cases the growth rates between 1984 and 1990 are greater than for the period 1990 to 2005, a reflection that current excess capacity permits higher near term growth than will occur as the economy moves toward its productive capability in the longer term.

The Canada growth projection to 1990 exceeds the experience of 1975 to 1984; over 1985 to 2005 the growth of real domestic product

Table 2-4

Real Domestic Product by Region

(Average annual growth rates - percent)

	1975-1984	1984-1990 Oil Price Case Low	1984-1990 Oil Price Case High	1990-2005 Oil Price Case Low	1990-2005 Oil Price Case High
Atlantic	2.6	2.1	2.2	2.2	2.2
Quebec	1.7	3.3	2.8	2.5	2.2
Ontario	2.4	4.0	3.3	2.7	2.4
Prairies	3.1	2.2	2.8	2.7	2.7
B.C. and Territories	3.1	3.0	2.5	2.5	2.3
Canada	2.5	3.3	2.9	2.7	2.4

Note: All numbers on this table have been rounded.
Source: Appendix Table A2-2

approximates that of 1975 to 1984 in the high oil price case, and exceeds it in the low case. As 1975 to 1984 was a period of higher oil prices than projected in our low oil price case, and as 1981 - 1982 was a period of unusually severe recession, these results in part reflect the relationship between oil prices and economic growth discussed above.

The regional growth rates reflect the judgements noted above about how higher or lower oil prices affect relative growth prospects of regions having different concentrations of energy resource production relative to other activities. Near term growth in Ontario is particularly responsive to the much lower projected oil prices in both oil price cases compared with those prevailing in the late 1970s and early 1980s.

These growth projections, and the factors underlying them have different implications for energy demand in different energy consuming sectors of the economy, because growth is not identical in each sector and the energy use per dollar of real income or output differs between them.

Sectoral Assumptions

The most interesting issues affecting commercial and industrial sector energy demand are whether service sector production will grow more or less than goods production in Canada over the outlook period, and whether there will be improvement in energy efficiency. Energy demand is affected not only by the rate of economic growth for Canada and its distribution across regions. It is also influenced by the distribution of growth across industries. Energy use per unit of output is much higher in goods producing than in service producing industries and there is substantial variation of energy use in the production of different kinds of goods.

Between 1971 and 1985, the service sector grew more rapidly than did goods production. Goods accounted for 35 percent of total Canadian output in 1971 but only 29 percent in 1985.

As an economy grows and matures, the basic *material* needs of a slowly growing population are increasingly satisfied with a smaller share of total productive effort than expended in the past. Furthermore, the pattern of consumer demand changes toward consuming more services such as education, health care, leisure and fitness activities, child and home care services, restaurant food, insurance and banking services, and other commercial services designed to make life easier. This movement is consistent with trends in population and lifestyle. As the population ages and as participation in the labour force increases, more people depend more heavily on services provided by others. Technological progress in the service oriented industries increases their attractiveness and their ability to compete for the consumer dollar.

While it would be tempting to project a continued increase in the share of services in total output over the outlook period, we have not done so. Between 1970 and 1985, growth of the service sector averaged 3.9 percent, outpacing industrial output growth of 2.4 percent. During that period the rate of household formation averaged almost 3 percent annually - well above the 1.4 percent we expect for the next twenty years. While consumers will demand more - and differing - services in the future, it is not clear that, when combined with the effect of slowing population growth, the net result will be a continued increase in the services' share of total output.

Canadian real industrial product (goods production) is projected to grow over the study period at 3.1 percent per year in the low oil price case and 2.7 percent per year in the high case. In both cases, these growth rates are very slightly higher than those of total domestic product, reflecting our view that the share of goods production in total product should be at least maintained.

Regarding the composition of industrial output, pulp and paper, primary metals and mining are the most energy intensive sub-sectors per unit of output. Together they accounted for about 22 percent of industrial product in 1971 and 20 percent in 1985. In 1985, they accounted for about 61 percent of the industrial sector's energy demand. In our projections there is very little change in their aggregate share of industrial output. These industries face severe competition from new entrants around the world and in some cases from substitute materials. However, our projections reflect the view that Canada has the resource base, experience, investment climate and technological capability to remain competitive in these industries.

If, contrary to our assumptions, the share of the service sector in real domestic product were to increase and the share of the pulp and paper, mining and primary metals sub-sectors in real industrial product to decrease significantly, energy demand would be lower than that in our projections.

Chapter 3
Energy Demand

In this chapter we examine end use energy demand by sector and by fuel, and for each major energy form we trace demand from end use to primary requirements. The distinction between end use and primary energy demand can be explained as follows:

- end use requirements include space and water heating, motive power for equipment, appliances and vehicles and process heat for industry;
- to arrive at the amount of primary energy used, we add to end use demand the amount of fuel and losses associated with the production and distribution of energy.

3.1 End Use by Sector

The behaviour of end use energy demand during the late 1970s and early 1980s was conditioned by high real energy prices and an expectation of future increases, reinforced for a time by a period of weak or declining income and output. Between 1980 and 1983 end use demand declined from a 1980 peak of 7060 petajoules to 6423 petajoules. This large reduction in energy demand, accompanied by a shift off oil, occurred in response to the 1980 oil price shock and to the recession of 1982 during which Canada's real Gross National Product declined by over 4 percent.

The recession had a strong impact on industrial energy demand. Both real industrial output and industrial energy demand dropped by about 10 percent in 1982.

In 1984, the strong recovery of the Canadian economy, particularly the manufacturing sector, led to an increase in total end use demand of almost 4 percent over that of 1983. Most of this increase consisted of a 6 percent rise in industrial energy demand.

Since the mid 1970s all energy-consuming sectors have adopted conservation measures, reflected both in changes in the stock of energy-using equipment (for example, home insulation) and in discretionary use of energy (for example lower temperatures for space heating and lower lighting standards in commercial buildings). At the same time improvements were effected in the energy efficiency of new appliances, cars, trucks and other energy-using goods. Most of these changes were predicated on the basis of expected high oil and other energy prices in the future.

There were other factors at work leading to reductions in end use demand. Many governments initiated energy conservation and substitution programs, the major federal programs for the residential sector being the Canadian Home Insulation Program and the Canadian Oil Substitution Program, and electric and natural gas utilities offered customers incentives to switch off oil, replacing inefficient with more efficient natural gas or electric equipment.

Collectively these factors led to a reduction in energy intensity in all sectors during 1973-84. That is, energy use per household, per unit of output, and per vehicle declined. In aggregate, energy demand per dollar of real GNP declined at an average annual rate of 1 percent over that period.

Our projections of end use demand are based on real oil and gas prices which in 1986 are far below the 1985 level and, while growing over the study period, approach the 1985 level only by 1993 in the high oil price case, but never reach it in the low case. However, our experience over the last decade is one of rapidly rising oil and gas prices. A major question in estimating future energy demand is whether consumers will increase their energy use in response to lower prices in the same way they decreased it in response to high prices.

Much of end use energy demand is determined by the characteristics of the existing stock of energy-using equipment; for example, the degree of insulation of existing houses, the age and efficiency of furnaces, the average fuel efficiency and age of the existing stock of cars, and the characteristics of commercial office buildings, industrial plants and their energy-using equipment.

In our view most of the efficiency gains achieved over the past decade will not be reversed, because it is unlikely to be economic to do so. Improvements in the energy efficiency of housing stock, industrial equipment, and automobiles may not be as rapid as they were since the mid-1970s, but it does not seem reasonable to assume that the energy-using capital stock will again be designed with the low levels of energy efficiency of the early 1970s. Automobiles are unlikely to revert to lower fuel efficiency.

Moreover, the increased awareness and concern for energy conservation which developed during the 1970s will probably continue despite the recent drop in oil prices, and despite the outlook for lower real oil and gas prices than previously expected. The changes in consumer behaviour relating to energy demand are well established and it is hard to imagine that energy consumers would revert to energy consumption practices which would make them vulnerable to potential price shocks.

Total end use demand is a composite of the requirements of the various energy consuming sectors and each sector's demand is affected by different factors. For this reason, we examine the energy requirements of each sector separately, concluding with total end use requirements. Before looking at sectoral demand, we begin with a summary of the energy price projections facing end use consumers in the two cases.

3.1.1 End Use Energy Prices

Between 1973 and 1984, consumers faced rising real energy prices. The world oil price increased at an average real rate of 16 percent. In Canada, prices of motor gasoline used by cars rose by 4 percent annually, while oil and natural gas prices for residential, and industrial consumers increased at rates of 6 to 14 percent. (Table 3-1)

Each fuel price has been adjusted to reflect that fuel's utilization efficiency in the sector. A utilization efficiency adjustment reflects the difference between the energy which goes into energy-using equipment and the energy released for end use. Energy prices adjusted for efficiency are also referred to as burner-tip prices. For light fuel oil 65 to 75 percent of the input energy is available for end use, while for electricity 100 percent efficiency is assumed. The efficiency of fuel use may improve over time, as, for example, more efficient furnaces are built.

Table 3-1

Real End Use Energy Prices

(Average annual growth rates - percent)

	1973-1984	1984-1990		1990-2005	
		Oil Price Case		Oil Price Case	
		Low	High	Low	High
World Oil Price $ US	16.2	-10.6	-5.7	0.8	1.4
Ontario Natural Gas Wholesale Price	11.7	-5.8	-0.6	0.6	1.1
Sectoral Prices					
Residential [a]					
Light Fuel Oil	12.7	-4.7	-2.2	0.2	0.4
Natural Gas	6.3	-2.7	-0.3	0.4	1.3
Industrial [a]					
Heavy Fuel Oil	13.9	-8.7	-4.6	0.6	1.1
Natural Gas	10.8	-4.8	-0.6	0.6	1.0
Transportation					
Car Gasoline	4.1	-2.4	-0.7	-0.1	0.2

Note: All numbers on this table have been rounded.
[a] These prices are adjusted for the fuel efficiencies of each sector.

Source: World Oil Price - Appendix Table A2-1

In Chapter 2 we described how we derived our world oil price projections. The difference in growth rates between the world oil price, domestic wellhead or wholesale prices, and prices to the final consumer reflect - among other things - government policy concerning domestic energy pricing, taxes and local utilities' costs of distribution to the final consumer. Similar factors cause differences between wholesale and retail natural gas prices. For electricity prices we have assumed no real increases for most of the projection period.

In the residential sector, prices of light fuel oil and natural gas do not decline as rapidly as the world oil price or the wholesale natural gas price between 1984 and 1990, but do not rise as rapidly as those prices over the 1990-2005 period. This is on account of the assumptions that refinery and distribution margins between crude oil and refined products remain constant in real terms over the study period, and that the distribution margin for residential natural gas maintains its real level. For residential light fuel oil and natural gas these margins account for about 30 percent of the burner-tip price.

In the industrial sector, the Canadian price of heavy fuel oil declines less steeply than does the world oil price between 1984 and 1990 and increases less strongly from 1990 to 2005. This happens because the Canadian price of heavy fuel oil includes transportation cost adjustments which remain constant in real terms.

Industrial natural gas prices track the wholesale natural gas price changes closely in both cases.

For gasoline prices, we assume that existing federal and provincial taxes are maintained either at the same percentage or at the same real level depending on the type of tax. Real changes in gasoline prices are less pronounced than changes in real oil prices because taxes, processing and distribution costs are a considerable proportion of the gasoline price and many of these costs do not change in real terms.

3.1.2 Residential Sector

The residential sector includes all household energy use, and diesel fuel used in agriculture. Energy used for space and water heating together accounts for almost 85 percent of household energy requirements; the remaining 15 percent is required for lighting and appliance operation.

Household demand for energy resources depends upon:

- *demographic factors* such as population, its age and sex structure and household formation;
- *lifestyle factors* such as number of persons per household, the character of the housing (for example single unit homes or apartment buildings) and standards of comfort (affecting heating and air-conditioning habits);
- *technical factors*, for example types of building designs, building materials, insulation and household equipment, which determine how much energy is needed to meet any given standard of service;
- *income* available to households, which determines the size of housing, type of heating equipment and penetration of energy-using appliances such as air-conditioners, television sets and others.

Table 3-2

Residential Energy Demand

(Average annual growth rates - percent)

	1973-1984	1984-1990		1990-2005	
		Oil Price Case		Oil Price Case	
		Low	High	Low	High
Households	3.0	1.9	1.9	1.2	1.2
Real Disposable Income per Household	0.3	0.6	0.1	1.5	1.5
Real Energy Price [a]	4.9	-1.4	-0.1	0.2	0.3
End Use Demand [b]	0.7	1.3	0.6	0.9	0.7
Energy Demand per Household	-2.3	-0.6	-1.3	-0.3	-0.5

(Levels)

	1973	1984	1990		2005	
			Oil Price Case		Oil Price Case	
			Low	High	Low	High
End Use Demand [b] (Petajoules)	1231	1326	1431	1373	1648	1523
Demand per Household (Gigajoules)	196	152	147	141	141	131

Note: All numbers on this table have been rounded.
[a]The energy price represents a weighted average efficiency adjusted fuel price for the sector.
[b] Adjusted for variations in weather.

Table 3-2 illustrates the relationship between growth in households, income, energy prices and demand in the two projections.

Patterns of energy use changed dramatically during the period 1973 to 1984. Energy use per household declined on average by 2.3 percent annually as real energy prices jumped almost 5 percent per year. Consumers' response to higher energy prices was reinforced by the existence of federal and provincial incentive programs promoting energy conservation and substitution away from oil.

These programs contributed to reshaping the characteristics of the housing stock and energy-using equipment in houses, so that both are now much more efficient than they were a decade ago.

Under the Canadian Oil Substitution Program some 1.2 million houses switched to fuels other than oil to meet their space heating requirements. These substitutions were generally to electricity, natural gas

and wood fuelled heating equipment incorporating technical improvements to increase their efficiency.

About 2.3 million households obtained grants under the Canadian Home Insulation Program to reduce their space heating requirements. We understand that participation in this program was estimated to be 40 percent of eligible houses. The majority of homeowners receiving home insulation grants undertook attic insulation. Thus, while a large part of the opportunities for energy conservation through attic insulation have been realized, many energy saving improvements to houses could still be made.

To date R-2000 homes (houses insulated to a very high standard) have had limited success. Some 1,500 units have been built. With lower energy prices the payback period for the additional investment in an R-2000 home is lengthened.

There are a number of assumptions underlying the projections for the two oil price cases.

- The number of households grows in both cases at an average annual rate of 1.9 percent between 1984 and 1990 and 1.2 percent between 1990 and 2005. New housing stock accounts for less than 2 percent of the total housing stock each year.
- Real income per household grows very slowly from 1984 to 1990 in both oil price cases. Modest growth of 1.5 percent per year is projected thereafter.
- The residential sector average real energy price declines at an annual rate of 1.4 percent to 1990 in the low price case and by 0.1 percent per year in the high price case. From 1990 to 2005 the energy price increases marginally in both cases.
- Although the Canadian Oil Substitution and Canadian Home Insulation Programs have terminated and oil prices have come down, there remains some interest in retrofitting and conversion to more energy efficient furnaces in both price cases.
- New oil and natural gas furnaces are currently estimated to be approximately 17 percent more efficient than the existing stock, and we anticipate continued improvements in furnace efficiency in both the low and high oil price cases.

In evaluating the effect on demand of future changes in income and housing characteristics we anticipate that higher incomes lead to larger houses, increased purchases and use of appliances and perhaps less conservative behaviour towards space and water heating. However, we do not expect to see a significant increase in residential energy demand in the face of rising real personal disposable incomes. New more efficient houses (on average about 25 percent) will continue to be constructed, contributing to an improvement in average housing energy efficiency. There will also be continued improvements in the fuel efficiency of furnaces and appliances. Finally, appliances which do not yet have high penetration or which are new to the market will be very energy efficient, mitigating the tendency for higher income to increase residential energy demand.

Under the low oil price case, we project that residential energy demand for Canada will increase at 1.3 percent annually between 1984 and 1990 and just under 1 percent per year thereafter. This implies a steady decline in energy demand per household averaging 0.6 percent per year in the short term and 0.3 percent in the longer run. Though there may be some reversal of energy efficient behaviour as a result of the lower energy price levels, energy savings arising from an increased proportion of more efficient new homes and equipment are likely to more than offset any such conservation reversals.

In the high oil price case real disposable income per household grows more slowly and real energy prices more rapidly. The number of households is virtually the same in the two cases. As a result, energy demand in the residential sector is lower in the high oil price case. Total residential energy demand for the two outlooks differs by 58 petajoules (4.2 percent) in 1990 and 125 petajoules (7.6 percent) by 2005.

We project a faster rate of decline in energy use per household in the high than in the low oil price case. This difference can be explained by the fact that higher prices encourage the adoption of more energy saving measures in the home, and increased interest in retrofits and the purchase of more energy efficient homes and household equipment.

Overall, in both cases energy use per household declines at a slower rate than experienced from 1973 to 1984 because over the projection period, the rate of renewal of the housing stock and growth in energy prices are slower than they were from 1973 to 1984. In both cases, we also project a slowdown in the rate of decline in energy use per household after 1990. This happens because during the early years of the projection period we continue to observe some lagged response to past price increases. After 1990 opportunities for further significant

savings in energy use should be more limited.

All regions are expected to experience higher residential energy requirements under the low oil price case than the high. This is true even for Alberta, which experiences less real income growth with lower energy prices. However, we anticipate that demand will respond more strongly to price changes than to income changes, such that the difference in prices between the two cases dominates what for Alberta is an opposing change in income.

3.1.3 Commercial Sector

The commercial sector energy demand includes that of all service industries except transportation and energy utilities. Approximately two-thirds of the energy used is for heating and cooling buildings. However, the types of buildings that make up this sector are diverse, including hospitals, schools, office buildings, corner stores and shopping centres.

End use energy demand in the commercial sector, shown in Table 3-3, grew less rapidly than that sector's output during 1973 to 1984, leading to a decline in energy intensity (energy use per dollar of output in this sector) averaging 1.9 percent per year. This resulted from measures ranging from adjusting lighting levels and resetting temperature and humidity controls to retrofitting existing buildings.

For the projection period, the following considerations about commercial sector growth, energy prices and energy efficiency affect energy demand.

Output of this sector tends to be more closely linked to population and government activities than to the vagaries of business cycles. The impact of a slower growing population over the remainder of this century is reflected in somewhat slower economic growth towards the end of the projection period. We expect little growth for schools and universities - there may even be some contraction - but an aging population will lead to more health care, restaurants and leisure services. Consequently, growth rates of commercial RDP (defined as the output of all service industries except transportation, storage and communications) for the high and low price cases are quite similar. Technological change has affected the service sector significantly, but its impact on employment and output are difficult to judge. The nature of output in many sectors has changed, but how energy requirements may be affected is not clear.

The projected decline in intensity comes about as newer, more energy efficient buildings replace some of the older, less efficient stock. This improvement will be dampened to some extent as older buildings without air conditioning are replaced by new air conditioned buildings. It may also be the case that increased use of computers and business machines will raise required floor space and energy needs per worker.

New office buildings are more energy-efficient than older buildings, despite the recent weakness in energy prices. Building codes, as well as the design and use of more sophisticated energy management systems, all contribute to reduced energy requirements. While the rate of improvement and adoption of

Table 3-3

Commercial Energy Demand

(Average annual growth rates - percent)

	1973-1984	1984-1990		1990-2005	
		Oil Price Case Low	High	Oil Price Case Low	High
Commercial RDP	3.2	2.7	2.5	2.4	2.2
Real Energy Price[a]	5.5	-1.0	0.4	0.4	0.5
End Use Demand	1.2	2.7	1.9	2.2	1.8
Intensity	-1.9	-0.1	-0.6	-0.2	-0.4

(Levels)

	1973	1984	1990		2005	
			Oil Price Case Low	High	Oil Price Case Low	High
End Use Demand (Petajoules)	762	872	1021	976	1420	1269
Intensity (Megajoules per $1971)	16.1	13.0	13.0	12.6	12.6	11.8

Note: All numbers on this table have been rounded.
[a] The energy price represents a weighted average efficiency adjusted fuel price for the sector.

such techniques may be slower in an environment of lower energy prices, we do not anticipate a reversal of the downward trend in energy intensity.

While energy demand in the commercial sector has responded more strongly to income than to price change in the past, the difference between the two cases presented here is attributed more to the different energy prices, as output growth is similar.

For the low oil price case, real energy prices in the commercial sector decline through 1990, before recovering slowly through 2005. We expect energy intensity to decline throughout the period even though for part of it energy prices are declining. This is in contrast with the 1973 to 1984 period when energy intensity declined at an average rate of 1.9 percent per year as prices rose 5.5 percent per year.

In the high oil price case, real energy prices rise steadily throughout the projection period. This results in greater declines in energy intensity than in the low oil price case; price is an important incentive for conservation.

3.1.4 Industrial Sector

The industrial sector includes the manufacturing industries, forestry, construction and mining, but excludes the petrochemical industry, which is discussed below. Although the industrial sector accounts for approximately 30 percent of total end use demand, most of its energy requirements come from only a small number of industries. The regional diversity of industrial structure and energy use in different sub-sectors leads to a large variation in regional industrial energy requirements per unit of industrial output.

Table 3-4

Intensity of Industrial Energy Use by Selected Industries in 1984

(Megajoules per 1971 dollar of industrial output)

Total Manufacturing	73
Pulp and Paper [a]	343
Iron and Steel	288
Chemicals[b]	121
Other Manufacturing	22
Smelting and Refining	188
Mining	70
Total Industrial [b]	57

Note: All numbers on this table have been rounded.
[a] Pulp and paper and allied products.
[b] Excludes feedstock used in the petrochemical sector.

Table 3-4 shows the energy intensity (energy use per dollar of industrial output) for major industries in 1984. The pulp and paper industry is the most energy intensive and accounts for the largest single share of industrial energy demand - over 30 percent. Together, pulp and paper, iron and steel, smelting and refining, and chemicals account for 60 percent of industrial energy demand. Table 3-5 shows Canada's diverse regional industrial energy intensity. Those provinces with large pulp and paper, smelting and mining sectors have higher industrial energy intensities.

Table 3-5

Intensity of Industrial Energy Use by Region in 1984

(Megajoules per 1971 dollar of industrial output)

Atlantic	91
Quebec	59
Ontario	46
Manitoba	37
Saskatchewan	75
Alberta	46
British-Columbia	102
Canada	57

Note: All numbers on this table have been rounded.

Major uncertainties about the prospects for industrial energy use include:

- whether industrial output will lose significant share to the service sector in the future;
- whether within the industrial sector there will be major shifts from the traditional resource-based energy intensive industries to those for which energy input is less important;
- the rate of adoption of energy saving techniques;
- the rate of adoption of new processes which affect energy demand; and
- the impact on energy demand of major technological developments, such as increased use of plastics or ceramics or changing material mix in production processes.

In Chapter 2 we suggested that industrial output will not lose share to the service sector over the study period. We also projected that the share of energy-intensive industries in industrial output would decline very moderately.

Energy conservation measures in industry can be categorized in two ways. The first kind of measure reduces energy use per unit of output without affecting the productivity of capital or labour in that industry, for example heat recovery techniques. The main purpose of these changes is energy conservation. The second results in reduced energy intensity because of a change to a particular industrial process, for example continuous casting in steel and aluminium smelting. The first kind of measure tends to be driven by changes in energy prices and by the return on the investment

in that process, while the second is usually motivated by broader process efficiency and output considerations than energy savings alone.

In many cases, it appears that technological change not specifically driven by energy prices may be one of the most important determinants of changing energy demand. Some of these changes include:

- greater application of thermo-mechanical pulping and chemi-thermo-mechanical pulping in the pulp and paper industry, which lead to increased electricity use and energy savings;
- use of basic oxygen furnaces, electric arc technology and continuous casting in the iron and steel industry; and
- increased automation of process control and adoption of more electricity-intensive processes, which lead to an increased electricity share and reductions in energy intensity.

Table 3-6 highlights the major quantitative factors influencing industrial energy demand and the resulting projections for the two cases. Over the 1973 to 1984 period growth in industrial production averaged 0.9 percent per year, heavily influenced by the 1982 recession. Between 1973 and 1981 industrial output grew by 1.5 percent per year. In 1982 real industrial production declined by 11 percent; the resource and manufacturing industries were particularly hard hit. The decline in output coupled with high energy prices prompted significant improvements in industrial energy use during the early 1980s. Industrial energy demand declined by 2.1 percent annually between 1980 and 1984, and energy intensity fell by 1.3 percent on average. Most of the improvements were concentrated in the iron and steel, smelting and refining and pulp and paper industries.

In our projections, energy demand growth in the industrial sector will be heavily influenced by economic activity, with energy prices playing a lesser role. In both oil price cases industrial output is expected to grow at over 2.5 percent per year over the projection period, much more rapidly than in the period 1973 to 1984. Energy prices, on the other hand, are projected to remain relatively flat when compared to the experience of the past decade. In the low oil price case, lower energy prices favour Canada's manufacturing sector, leading to stronger output growth and consequently higher energy demand than in the high price case. Industrial energy demand growth surpasses the growth over 1973 to 1984, despite anticipated reductions in energy intensity. Because energy intensity continues to decline, industrial

Table 3-6

Industrial Energy Demand

(Average annual growth rates - percent)

	1973-1984	1984-1990		1990-2005	
		Oil Price Case		Oil Price Case	
		Low	High	Low	High
Industrial RDP	0.9	4.1	3.4	2.8	2.5
Real Energy Price [a]	7.8	-2.1	-0.8	0.2	0.5
End Use Demand [b]	2.1	3.3	2.5	2.4	1.9
Intensity [b]	1.1	-0.8	-1.0	-0.5	-0.6

(Levels)

	1973	1984	1990		2005	
			Oil Price Case		Oil Price Case	
			Low	High	Low	High
End Use Demand [b] (Petajoules)	1682	2104	2553	2445	3629	3277
Intensity[b] (Megajoules per $1971)	50.4	57.0	54.5	53.7	50.9	49.4

Note: All numbers on this table have been rounded.
[a] The energy price represents a weighted average efficiency adjusted fuel price for the sector.
[b] The increase in end use demand and energy intensity between 1973 and 1984 is due mainly to inclusion of fuels not previously recorded in energy demand data. For example, after 1973, hog fuel and pulping liquor, steam and petroleum coke were added to energy demand. If these fuels were excluded, measured energy intensity would have shown a decline of 0.8 percent per year and end use energy demand an increase of only 0.5 percent per year over that period.

demand for energy grows less rapidly than industrial output in both oil price cases.

The rate of decline in energy intensity in both cases is higher in the medium term than in the 1990-2005 period. This trend reflects the view that, despite present low energy prices, the rapid application of energy conservation measures and technologies that was triggered by the energy price shocks of the late 1970s and early 1980s will continue over the next few years. By the end of the 1980s, most of the relatively easy-to-apply and cheaper energy savings measures and technologies are likely to be in place. In the long term, savings in energy use will come largely from the replacement of existing capital by more efficient capital, and from technological changes.

The impact of changing industrial structure on energy demand is significant. In both the low and high oil price case the share of pulp and paper, smelting and refining and mining in total industrial output declines over the outlook period. In the low price case, for example, their share declines from 17 percent in 1984 to about 15 percent by 2005. If this share were constant over the projection period, industrial energy demand of these three industries would be almost 140 petajoules, or 7.3 percent higher in 2005 in the low price case.

By 2005 industrial energy demand in the low oil price case is 11 percent (352 petajoules) higher than in the high oil price case. Almost 45 percent of this difference can be attributed to differences in the regional/sector mix of industrial output between the two cases, most of the remainder being due to differences in the extent and timing of the adoption of energy-saving technologies. A small proportion results from an increased use of electricity - a more efficient fuel - in the high oil price case.

3.1.5 Non-Energy Hydrocarbon Use

Approximately 10 percent of total end use energy demand goes to non-energy uses. In 1984, this amounted to 674 petajoules. Of this total, 484 petajoules (72 percent) was accounted for by petrochemical feedstock requirements, 100 petajoules (15 percent) by asphalt, and the remainder by lubricants, greases, petroleum coke and other non-energy petroleum products.

The petrochemical industry worldwide has experienced large capacity increases in recent years which, combined with a substantial reduction in growth of demand for many of its products has led to a capacity surplus. Most analysts anticipate that petrochemical product demand will grow at or slightly above the rate of GNP growth, but not at the much higher past growth rates when there was rapid penetration of plastics products in all markets.

There has been significant petrochemical capacity expansion in Canada in recent years - most of it based on natural gas and ethane. At present, over 60 percent of petrochemical feedstock demand is in Alberta, and over 60 percent of total feedstock requirements are met by natural gas. As a reaction to the Canadian oil price increases of the early 1980s, plants in eastern Canada have increased their ability to switch from oil to ethane, propane and butanes.

Projections of petrochemical feedstock demand depend on several crucial and uncertain factors:

- Canada's competitive position in the world petrochemical market, which will be affected by a combination of relative feedstock costs, capital and operating costs and access to markets;
- the timing of new Canadian plants during the projection period, which will be affected by the world-wide scheduling of plant capacity, and by the growth in product demand;
- the mix of feedstock demand, which will vary with relative feedstock prices and product slate requirements.

In general, due to the world-wide surplus capacity for major petrochemical products, their prices have been so depressed that producers have not always recovered their operating costs. This is a global problem, affecting the industry in Canada and other countries. To operate efficiently and minimize production costs per unit of product, plants have to run at essentially full capacity. In this industry it is generally preferable to shut down than to run at partial capacity utilization, producing high cost, uncompetitive output.

Much Canadian capacity is relatively new, world-scale and technically efficient. Modification and modernization of older units have taken place, and some Canadian plants produce specialized products. Given the objective of a viable petrochemical industry in Canada, our projections assume that existing facilities will continue to operate. This presumes that market conditions will enable producers to overcome current problems of poor profitability. Canada's industry must be internationally competitive to survive; as in the past, this means overcoming disadvantages related to

capital costs, freight and tariffs. While these disadvantages were overcome by a feedstock cost advantage in past years, there is concern that deregulation of natural gas prices in both Canada and the United States will tend to equalize gas feedstock costs between plants in North America.

With the current world-wide surplus of production capacity for a number of major products, new plant investment is being approached with much more caution than it was in the 1970s. While there are a number of ethylene projects underway in various parts of the world, most of these will not add new capacity but rather improve the efficiency and flexibility of existing plants. With growth in petrochemical product demand generally anticipated to match or slightly exceed overall economic growth, it is likely that international supply and demand will be in balance within the next ten years, raising the possibility of investment in new primary petrochemical plant in Canada. Since perceptions of market potential and investment strategy vary significantly among industry analysts, especially about the timing and location of new plants world wide, our assumptions regarding Canadian capacity additions could be viewed as optimistic by some but conservative by others.

Whatever the world oil price scenario, petrochemical prices are determined on the world market, Canada is a relatively small producer of most primary petrochemicals and Canada's ability to supply domestic and foreign markets will depend on the competitiveness of its products. As long as we assume that Canadian plants will be competitive, it is reasonable to assume that they will operate at about full capacity in either oil price case. Therefore, we assume the same demand for petrochemical feedstock in both oil price cases.

Between 1986 and 2005 we allow for the construction of eight ammonia plants, mainly in Alberta, adding a total of 65 petajoules per year of natural gas demand when all are operating at capacity. Three of these plants are scheduled to come on stream in 1986-87, the remainder not until after 1990.

One additional ethylene plant is assumed for Alberta in 1995, requiring 44 petajoules of ethane and about 5 petajoules of natural gas annually. No new methanol capacity is assumed for the projection period due to the prospect for continued substantial worldwide overcapacity. Increased use of methanol as a fuel or blending agent could justify new capacity before 2005.

Petrochemical feedstock requirements for natural gas are projected to reach 400 petajoules by 2005 from about 300 petajoules in 1985. Ethane use increases from about 70 petajoules in 1985 to 126 petajoules by 2005 as existing plants approach full capacity and the additional ethylene plant is commissioned.

We allow for increased use of liquefied petroleum gases (LPG) as a result of increased feedstock flexibility in eastern Canada's petrochemical production, from under 30 petajoules in 1985 to just over 60 petajoules by 2005. Use of oil for feedstock declines by a similar amount, to 100 petajoules in 2005.

These projections assume that producers make significant use of LPG but it is possible that oil may remain competitively priced relative to LPG, or that other factors may lead to less use of LPG and more of oil than we have projected. These estimates reflect only one of a number of options producers have to meet a particular product slate.

Road paving accounts for 75 to 80 percent and roofing most of the remainder of total Canadian asphalt demand. Asphalt demand declined from 146 petajoules in 1979 to 105 petajoules in 1984 (its approximate level in 1970-71). Since 1979 there has been an almost continuous decline in new asphalt demand, related to weak economic activity in 1980-82, less road-building activity, improved efficiency in asphalt use and increased recycling of asphalt for road building. Other uses of asphalt besides road paving include: roofing, railroad bedding, and insulation of underground waterpipes and communications cables.

Over the next twenty years we expect recycling to play an important role in moderating demand for new asphalt, although there are limitations on the use of recycled asphalt for paving, due to quality considerations. We project asphalt demand to be 172 and 176 petajoules in 2005 in the high and low oil price cases, an average growth of about 2.5 percent per year. However, as there was a strong demand recovery in 1985, growth over the twenty year period 1985-2005 is only 2.0 percent per year.

Other non-energy products from energy resources include lubricating oils and greases, petroleum coke, naphtha specialties and other petroleum products. Together these account for about 13 percent of non-energy demands, and are projected to grow at 2.5 and 2 percent annually in the low and high oil price cases respectively. By 2005, we expect these uses to account for less than 2 percent of total energy requirements.

3.1.6 *Transportation Sector*

The transportation sector includes road, rail, air and marine transport. In 1984, transportation uses accounted for 26 percent of total end use demand and 62 percent of end use oil demand. Within the sector, road transport is most important, accounting for 81 percent of transport energy use in 1984, up from about 75 percent in the early 1960s. Figure 3-1 shows the distribution of transportation energy use by mode of transport. Clearly, change in use of road transport has a significant effect on change in total demand for oil.

Some of the most significant changes in energy demand since the early 1970s have occurred in this sector, particularly road transport. Transportation energy demand behaved differently between the periods 1973-1980 and 1980-84. During 1973-80, transportation energy demand rose 3.5 percent annually, and road transport demand almost 4 percent. This compares with declines of 3 and 2.5 percent per year respectively in 1980-84.

Between 1971 and 1979 new car sales increased at 3 percent annually. From 1979 to 1982, new car sales fell by a total of 29 percent, or 11 percent on average each year. This reflected the impact of high energy prices, weak - and in 1982 declining - real disposable income per household, and interest rates above 15 percent in 1981 and 1982. All these factors caused individuals to postpone either the normal replacement of existing automobile stock, or the purchase of additional vehicles. The delay related to stock replacement led to a strong recovery in new car sales in 1983-85. Average growth from the 1982 level was 17 percent annually through 1985.

Other factors influencing the decline in road transport energy demand over 1980-84 were:

- major improvements in new car fuel efficiencies for both large and small cars, compounded by a continued shift towards smaller cars; the small car share of new car sales rose from 56 percent in 1978 to 61 percent in 1984;
- a decline in energy use by trucks, although smaller than the decline in energy use by cars.

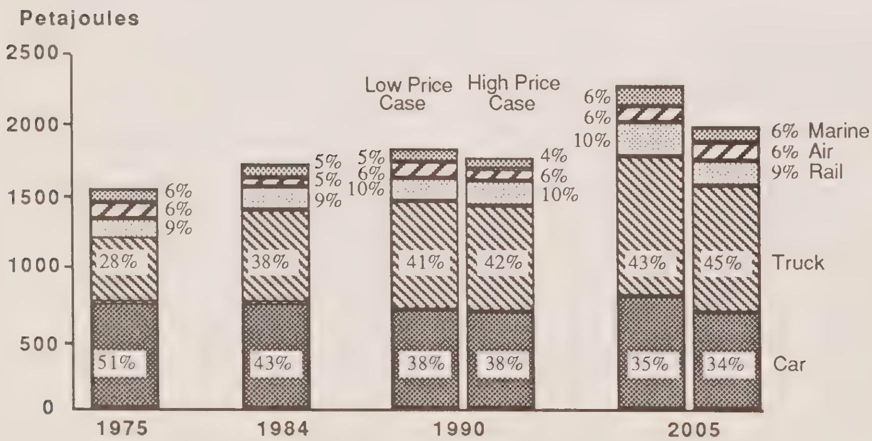
Table 3-7 sets out some of the major assumptions and factors influencing transportation energy demand, along with the growth rates in our projections.

Our projections for road transportation distinguish between car and truck demand. For cars, energy demand depends on new car fuel efficiencies, the ratio of large to small car sales, the rate of stock replacement and distance driven. Our assumptions in these areas reflect our view that there will not be a major reversal of efficiency gains realized between 1973 and 1984 and consumer attitudes toward oil use.

Our projections of automobile energy use rest on a number of considerations.

- We project a gradual increase in the number of cars per household in both cases, from 1.24 cars per household in 1984, to 1.33 by 2005 in the high oil price case, and 1.42 in the low oil price case, where real disposable income growth is stronger. (In the United States, there are now 1.49 cars per household.) Several factors could dampen further penetration of cars, leading to a lower number of cars per household than we have projected. New car prices have risen more rapidly than overall inflation during the past five years and there have been real increases in some major operating costs such as insurance.

Figure 3-1
Distribution of Transportation Demand by Sector



Source: Appendix Table A3-2

Table 3-7

Transportation Energy Demand

(Average annual growth rates - percent)

	1980-84	1984-1990 Oil Price Case Low	1984-1990 Oil Price Case High	1990-2005 Oil Price Case Low	1990-2005 Oil Price Case High
Explanatory Variables					
Real Gasoline Price for Cars	7.1	-2.4	-0.7	-0.1	0.2
New Car Sales	1.0	4.4	3.4	1.2	1.0
Car Stock	1.3	2.7	2.5	1.9	1.4
New Car Fuel Use per Kilometre	-6.4	-0.6	-1.5	-0.5	-0.7
All Car Fuel Use per Kilometre	-4.2	-4.2	-4.5	-0.8	-1.2
New Truck Sales	-1.5	6.7	6.4	1.7	1.3
Truck Stock	1.2	3.6	3.5	2.4	2.0
All Truck Fuel Use per Kilometre	0.0 [a]	-0.2	-0.2	-0.6	-0.9
Energy Intensities					
Energy Use per Car	-5.4	-3.8	-4.1	-0.9	-1.4
Energy Use per Truck	-1.6	-0.9	-0.8	-0.6	-0.8
Energy Demand					
Total Transportation	-3.2	1.0	0.5	1.5	0.8
Road	-2.5	0.7	0.4	1.4	0.7
- Cars	-4.2	-1.1	-1.7	0.9	0.1
- Trucks	-0.2	2.7	2.5	1.8	1.2
Rail	-2.1	3.2	2.5	1.4	1.1
Air	-2.7	2.3	1.4	1.8	0.6
Marine	-13.2	0.9	-1.0	2.5	2.3

Note: All numbers on this table have been rounded.
[a] 1982 to 1984.

Source: Energy Demand - Appendix Table A3-2

- New car fuel efficiencies continue to improve for both large and small cars, although at a slower rate in the low oil price case than in the high. Fuel efficiency of new cars is assumed to improve by about 1 percent annually over 1984-2005 in the high oil price case, and about 0.5 percent in the low.
- The share of small cars in new car sales declines slightly from 61 percent in 1984 to 58 percent in 2005 in the low oil price case but increases to 65 percent by 2005 in the high.
- There is no change in distance driven per automobile in spite of income or price changes. This indicator has remained very stable for many years, despite massive shifts in energy prices and income.
- New car sales in 1984-90 are projected to increase at an average annual rate of 3.4 to 4.4 percent in the high and low cases respectively. This is substantially above the average 1 percent growth over 1980-84. Our outlook for 1984-90 - which includes the rebound in 1985 - is broadly consistent with historical experience. Between 1990 and 2005 new car sales grow at about 1 percent per year in both cases.

Fuel efficiency is the most critical determinant of automobile energy consumption. There are major uncertainties surrounding expected car fuel efficiency improvements. If we were to assume no change in fuel efficiencies from 1984 levels, demand for motor gasoline used by cars would be 8 to 16 percent higher by the year 2005 - without taking into account any changes in the small/large car mix.

We are assuming no major increases in the shares of propane and natural gas for vehicles (NGV). Federal incentives for conversion are expiring, and the levels of oil prices in both cases result in a fairly long payback period for installing conversion equipment. However, some fleet conversions may still be attractive. The share of propane and NGV in road sector energy demand is projected to increase from 0.9 percent in 1984 to 1.7 percent in 2005 in the low oil price case and to 3.2 percent in the high case. By 2005 we estimate that 240 000 and 400 000 cars will use propane or NGV in the low and high oil price cases respectively, about 1 and 2 percent of vehicle stock in that year. (In the September 1984 Report we had projected a fuel market share of 5 percent for propane and NGV by 2005 corresponding to some 560 000 cars or 3 percent of the vehicle stock. This projection was consistent with the higher oil price projections in that report.)

Our assumptions lead to a projected decline in car energy demand of 1.1 to 1.7 percent annually over 1984-1990, but an increase in demand of between 0.1 and 1.0 percent over the next 15 years (Table

3-7). By 1990 (2005) car energy demand is 674 (680) and 698 (798) petajoules in the high and low cases respectively compared to 747 petajoules in 1984.

New truck sales are expected to increase at about 6.5 percent annually between 1984 and 1990, slowing to about 1.5 percent growth thereafter. The 1984 to 1990 projection appears to be a considerable reversal of the 1980 to 1984 experience (Table 3-7). However, the pattern of new truck sales from 1971 to 1984 was similar to that of cars. Between 1971 and 1979 growth of new truck sales averaged almost 12 percent annually. From 1979 to 1982, truck sales declined by 19 percent a year, and in 1982 they were below the 1973 level of sales. With the strong recovery after the 1981-82 recession, truck sales rose by 24 percent a year between 1982 and 1985. The estimate of 6.5 percent for 1984-90 includes a 26 percent gain in 1985. These projected increases in truck sales result in an annual growth of truck stock over 1984-90 of 3.5 percent on average, slowing to 2-2.4 percent during 1990-2005.

During the late 1970s and early 1980s improvements were made in truck transportation which led to fuel efficiency gains. Design changes were introduced and loads were organized to maximize truck fuel efficiency. This is true for all types of trucks, but particularly for diesel trucks weighing more than 15 000 kilograms and used for long-distance transport. These improvements, coupled with the fact that the use of trucks for transporting goods restricts the scope for fuel efficiency gains arising from weight reduction, have led us to project truck stock fuel efficiency gains of 0.2 to 1.0 percent over the period. For light gasoline trucks fuel efficiency gains are 1.0 percent annually over the twenty years in the high oil price case, but slow after 1990 to 0.6 percent in the low oil price case. For extra-heavy diesel trucks improvements are projected at 0.8 percent in the high oil price case for the twenty years; in the low oil price case these improvements slow to 0.5 percent from 1990 to 2005.

With the weaker fuel efficiency gains we have assumed for trucks relative to cars and given the growing requirements for truck transportation of goods, energy demand for truck use is projected to increase at about 2.5 percent per year between 1984 and 1990 in both cases, slowing to between 1.8 and 1.2 percent annually in 1990-2005 in the low and high oil price cases, respectively.

There is little difference in the distribution of truck stock between light and heavy, and between gasoline and diesel trucks in the two cases. The share of diesel trucks remains flat at about 4 percent throughout the projection period. This plus our assumption of less fuel efficiency improvement for diesel-powered than gasoline trucks leads to an increase in the diesel share of road energy demand, from 17 percent in 1984 to about 25 percent by 2005, in both oil price cases.

In total, road transportation energy demand is projected to increase at 0.4 to 0.7 percent per year on average between 1984 and 1990 in the high and low oil price cases, respectively. From 1990 to 2005, demand growth is somewhat higher (0.7 and 1.4 percent in the low and high oil price cases respectively) as fuel efficiency gains slow down.

In the September 1984 Report reference case we projected energy demand for road transport to decline by almost a full percentage point annually through 1990, then to increase by just under one percent a year thereafter. The major reason for the much lower growth in the 1984 Report is the assumption of much stronger fuel efficiency improvements in that Report, based on a projection of higher oil prices.

Air transportation accounted for 9 percent of transportation energy demand in 1984 and rail and marine accounted for 5 percent each.

Airlines do not anticipate the rapid increase in energy use of the 1960s and 1970s to be repeated in the future. High fuel costs and the impact of the 1981-82 recession on air travel have led the industry to undertake considerable rationalization - increasing load factors and modifying fleets to more efficient aircraft. Growth of passenger kilometres is expected to be modest compared with that of the previous twenty years, but the impact of deregulation on demand for air travel, airline operations and energy demand is uncertain. Some analysts have suggested that improved load management and less rapid growth in travel means that airlines' energy demand will grow little over the next twenty years. We are not adopting such an extreme view; we project air sector energy demand to increase on average at 1 percent over 1984-2005 in the high oil price case and 2 percent in the low oil price case.

Rail and marine transport is used mainly for shipping bulk goods such as grains, coal, iron ore and logs, although rail is also used on occasion to move some manufactured goods. Consistent with recent experience in these sectors, we expect energy demand to lag output growth, averaging 1.9 percent and 1.5 percent for rail in the low and high oil

price cases for 1984-2005, and 2.0 and 1.3 percent respectively for the marine sector.

Summary

Total end use energy demand for Canada, as projected in our two oil price cases is shown in Figure 3-2. In the high oil price case growth over the period 1984-2005 is 1.5 percent on average, as compared to 1.9 percent in the low oil price case. By 2005, this results in a 10 percent difference in the levels of national end use energy demand. Expressed in terms of energy demand per unit of output - or energy intensity - both projections show steady declines of -0.8 percent and -1.0 percent a year from current levels in the low and high oil price cases respectively.

Energy demand does not differ greatly between the two oil price cases, notwithstanding the rather large difference of oil prices between them. This is largely a result of our view that there will be low responsiveness of demand to differences of energy prices. A number of factors account for this expectation.

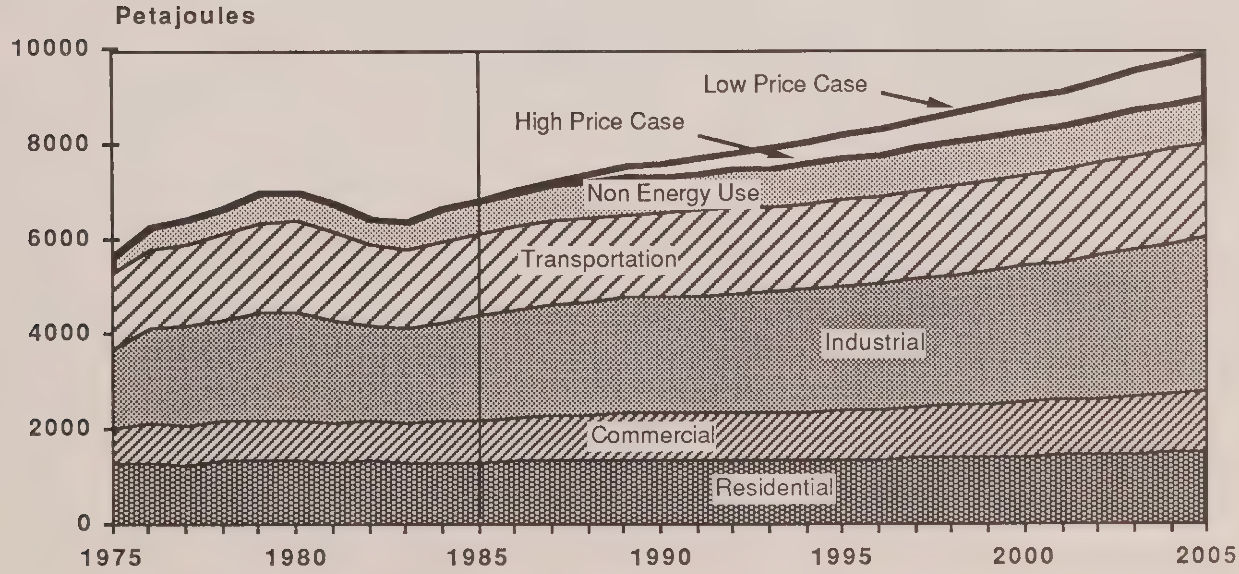
Structural factors now play an increasingly important role in determining energy demand. In the residential and commercial sectors the characteristics of existing buildings have a major role in determining energy demand, and these characteristics are not sensitive to future price and income changes. Similar arguments apply to the industrial sector, where existing processes, capital stock and machinery characteristics will continue to affect future demand. As well, consumer attitudes will continue to favour energy conservation, given the uncertainty of future prices. On-going technological change is expected to add to the fuel efficiency gains realized in the 1970s and early 1980s.

Sectoral shares of energy demand do not differ between the two oil price cases, although they do change over the projection period. Between 1984 and 2005 the residential share of end use demand falls from 19 to 17 percent; the commercial sector's share increases from 13 to 14 percent. Industrial energy demand increases its share from 32 to 36 percent. That of transportation declines from 26 to 22 percent. Non-energy (petrochemical) requirements are stable throughout the study period at 10 percent of end use demand.

Output and income could vary significantly from our projections, directly affecting the level of energy demand. It is conceivable that the range of future energy demand could be much wider than we have shown here, meaning that energy demand in the year 2005 could fall outside of the 9 000 to 10 000 petajoule band.

Figure 3-2

Total End Use Energy Demand



Source: Appendix Table A3-2

3.2 End Use Energy Demand by Fuel and Region

The pattern of fuel use has changed dramatically in Canada over the past decade. The shift away from oil in favour of electricity, natural gas and other fuels which occurred in response to the surge in real prices in 1973-74 and 1979-80 has been extensively documented.

It is difficult to discuss in any detail the evolution of fuel demands without focussing on each region. Apart from transportation, the fuel requirements of each region vary depending in part on differences of industrial structure between them.

Oil still satisfies a substantial share of energy demand in Atlantic markets, while in Quebec the availability of natural gas and abundant hydroelectric resources provide more opportunity for interfuel competition. In the west natural gas is used extensively, although in British Columbia and Manitoba hydroelectricity offers a competitive alternative.

The increase in prices of conventional energy forms in the 1970s and early 1980s sparked interest in alternative, renewable energy sources. One notable example is the use of wood for residential heating in the Atlantic provinces. Another is the use of hog fuel and pulping liquor in the pulp and paper industry.

In the following section we outline our views on the prospects for alternative energy sources, then turn to a regional analysis of end use demand by fuel - focussing on the characteristics of the regional markets which affect fuel choice, ending with a summary of the outlooks at the national level.

3.2.1 Alternative Energy

Alternative energy includes hog fuel and pulping liquor, wood, solar, wind and municipal solid waste.

In the 1984 Report we discussed the outlook for alternative energy sources, including renewable energy, of all types. Our views on the costs of various forms of alternative energy, and the conditions for penetration of these energy forms have not changed.

The degree of penetration of alternative energy sources depends on their costs, relative to the costs of other energy forms. We have no evidence causing us to lower the real cost estimates for alternative energy forms shown in the September 1984 Report. As our present outlooks are characterized by much slower real price growth for conventional energy, we are now less optimistic about penetration of alternative energy.

In our low and high oil price cases we expect renewable energy forms to account for 6 and 7 percent respectively of end use energy demand in 2005, about the same proportion as in 1984 and as was projected for 2005 in the 1984 Report.

Hog fuel and pulping liquor have become an important energy source for the forest products sector. While we anticipate that they will continue to play an important role in meeting that sector's future requirements, increased use of thermo-mechanical pulping and constraints on the forest industry's output over the long term - particularly in British Columbia - are likely to restrict growth of hog fuel and pulping liquor use.

Wood use in the residential sector has increased dramatically since the mid-1970s. However, with the projections of oil and natural gas prices substantially below those of earlier years - and with real oil prices not anticipated to return to 1981 levels again over the next twenty years - it is unlikely that further substantial increases will occur in residential wood use. Its share is likely to remain near its present level of 3 percent of residential energy use.

Disposal of municipal solid waste is becoming increasingly difficult. Many municipalities are considering construction of municipal solid waste plants to generate electricity; however, there are environmental obstacles to obtaining acceptable locations for them. We assume that some will be built and we have included some 35 petajoules of energy from municipal solid waste plants in both cases.

A nominal amount of solar energy and energy from agricultural sources is also included in our projections, increasing from 1 petajoule in 1984 to 9 petajoules by 2005.

Technological developments which reduce the cost of these energy forms could result in a significantly larger share of renewable and alternative energy forms than we have projected under our energy price assumptions.

Regional considerations - particularly in respect of available alternative energy sources - may favour development and use of renewable and other non-conventional energy forms in some regions over others. Technological developments may also make some small-scale use of solar or wind energy feasible in some areas. However, we anticipate that the outlook for only moderate increases in conventional energy prices from their present relatively low level, will hinder the further penetration of renewable and alternate energy forms. Nevertheless, we do not project a deterioration in

the level of energy requirements met by renewable sources.

3.2.2 Atlantic Region

The Atlantic region has made significant strides since the early 1970s in reducing its dependence on oil. Oil's share of end use demand has declined from 82 percent in 1973 to 64 percent in 1984. Though there has been some shift towards electricity, increased use of wood in the residential sector and wood waste in the industrial sector account for most of this change. During the projection period, to the year 2005, we expect wood to increase its share of residential energy demand in the high oil price case to 29 percent from 24 percent in 1984, at the expense of oil, due to the higher oil price. In the low oil price case wood's share is maintained at about its present level. Any further penetration of wood beyond what we have shown is expected to be restricted because of constraints on its availability and its relatively high price.

Energy shares in the industrial sector show virtually no difference between the two price cases. Electricity's share increases from 28 percent in 1984, to 36 percent by 2005, reflecting increased use of electricity by the pulp and paper industry, which accounts for more than half of the Atlantic region's industrial energy demand. Electricity's share rises at the expense of hog fuel and pulping liquor as new technologies in pulp and paper are increasingly used, and as the availability of steam to the industrial sector ceases with the closure of the heavy water plant in Nova Scotia.

In both oil price cases, oil is less expensive than electricity on an efficiency-adjusted basis in the residential, commercial and industrial sectors, but uncertainty over future oil prices will likely continue to influence consumers' choice.

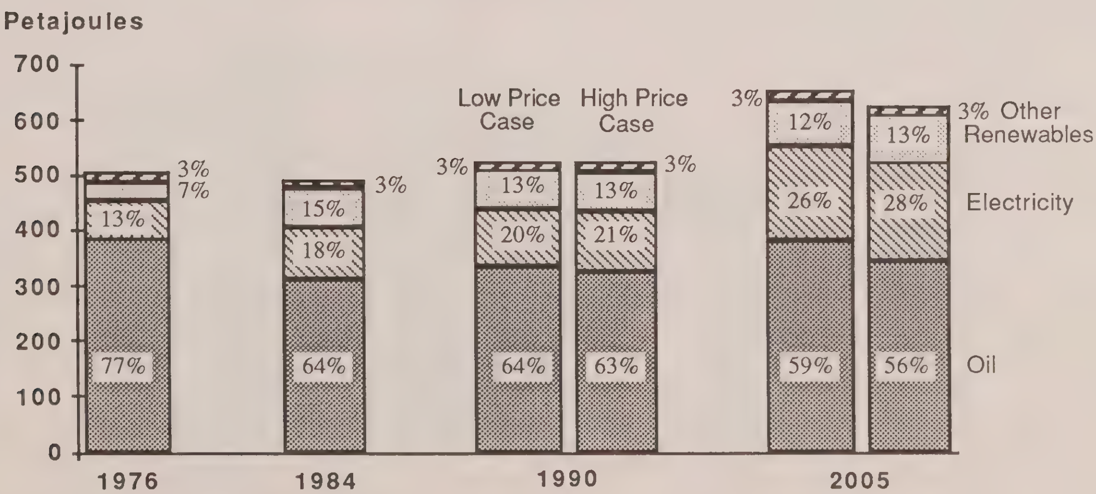
The projected levels and shares of end use demand (including transportation demand) in the Atlantic region are shown in Figure 3-3.

3.2.3 Quebec

The Quebec energy market has been characterized by intense competition between natural gas and electricity in recent years. With the completion of the natural gas pipeline and laterals in the province, natural gas utilities offered incentives to encourage gas use in the Quebec market. In addition federal programs such as the Canadian Oil Substitution Program provided a further incentive to switch off oil. During this period, Hydro-Québec had surplus electricity which it marketed by offering incentives for conversion to electric or dual-fired residential furnaces and industrial boilers. As a result, approximately 5 percent of Quebec's housing stock currently has dual heating ability. In the industrial sector the resulting structure is even more flexible as many plants now have the ability to use heavy fuel oil, natural gas or electricity.

Like the Atlantic region, Quebec made significant moves to reduce

Figure 3-3
End Use Demand By Fuel
Atlantic



Source: Appendix Table A3-6

its dependence on oil from 1973 to the early 1980s. Oil's share of end use energy demand fell from 73 percent in 1973 to 47 percent in 1984. The increased availability of natural gas, coupled with federal government subsidy programs and incentives from the electric power and natural gas utilities, boosted electricity's share from 19 percent in 1973 to 32 percent in 1984, and that of natural gas from 5 to 12 percent.

Most of the incentive plans offered by the utilities have now expired, and the natural gas market is more mature. Therefore, the choice of fuel in most Quebec markets will now be guided largely by unsubsidized relative fuel prices.

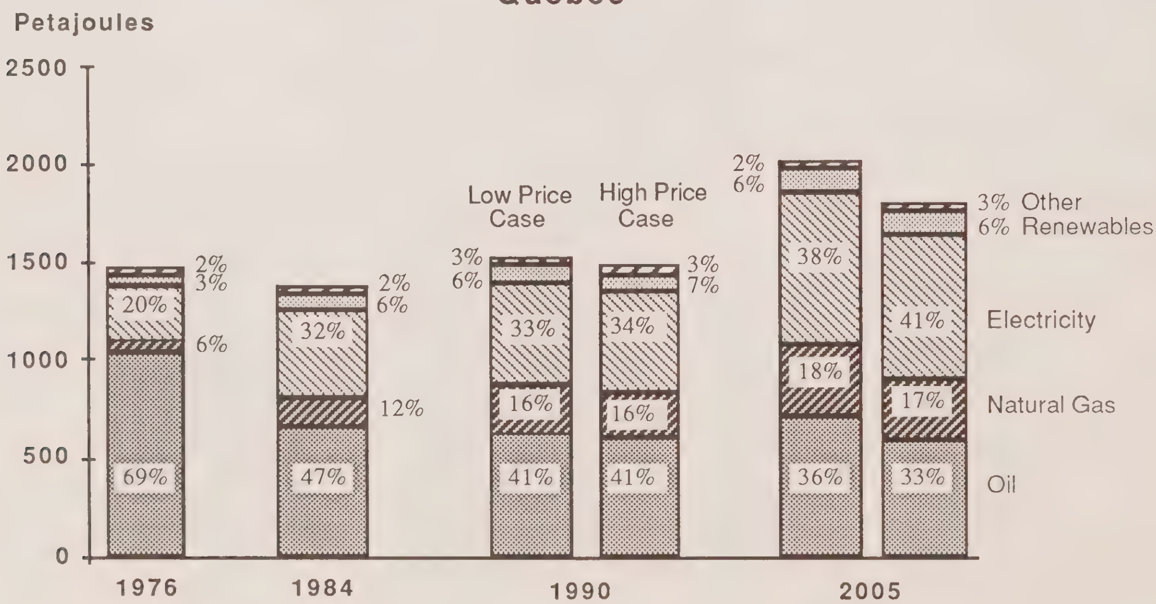
Over the long run, we expect the shares of electricity and natural gas to increase at the expense of oil in both cases. Figure 3-4 shows the levels and distribution of fuel demands for the two cases. In the high oil price case, the relative price of electricity is more favourable than in the low case, leading to a slightly higher share of electricity (41 percent) in end use demand as compared to the low case (38 percent).

In the residential sector in Quebec the use of oil continues to decline in both cases, conversions being largely to electricity. We do not expect any change in the preference of many Quebec residents for electricity over natural gas as a heating fuel for single family and small multiple units - despite the price advantage of natural gas. However, large apartment buildings may choose natural gas over electricity because of a price advantage resulting from differing utility rate structures for the two fuels. Wood presently accounts for about 11 percent of residential requirements, and its share is expected to rise only slightly given the price levels of other energy forms.

Industrial energy use is heavily influenced by the province's industrial mix. Process-oriented changes are likely to have a significant impact on industrial fuel shares. In 1984, pulp, paper, smelting and refining together accounted for over 50 percent of industrial energy demand. Adoption of thermo-mechanical pulping is expected to reduce pulp and paper requirements for hog fuel and oil in favour of electricity. The smelting industry will use primarily electricity. Construction of new smelters will increase that sector's requirements, but replacement of older plants with more efficient processes will partly offset the additional demand of the new plants.

Figure 3-4

End Use Demand By Fuel Quebec



Source: Appendix Table A3-6

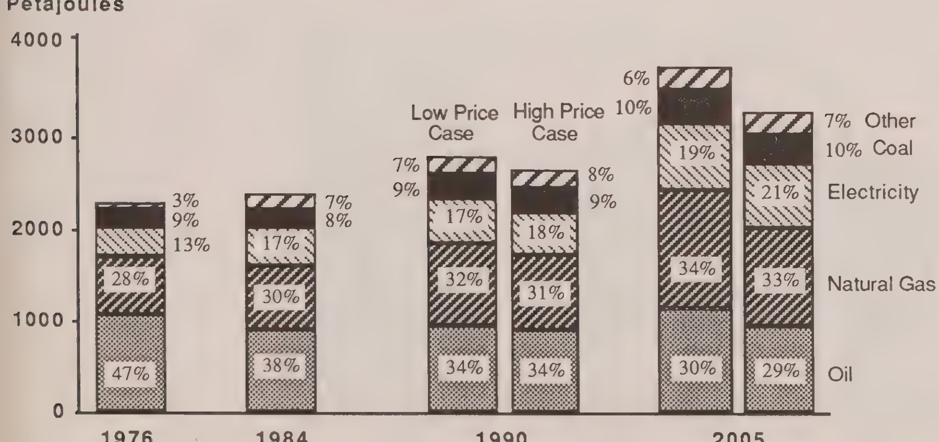
Hydro-Québec is currently selling surplus electricity to that province's industrial sector. These sales, of approximately 37 petajoules, will end in 1989 at which time consumers may meet some of this requirement with natural gas. Over the long run due to changes in industrial processes and plants mentioned above, electricity's share of industrial demand is expected to be maintained at 47 to 49 percent.

In the short term we expect intense competition between natural gas and heavy fuel oil in the dual fuel portion of the industrial market. In 1986, there is already evidence of the loss of some natural gas loads to heavy fuel oil. With the recent decline in heavy fuel oil prices, the deregulation of natural gas prices and the fuel-switching ability within the Quebec industrial market, there is considerable uncertainty as to future market shares in this sector. For our projections we assume a continued long-term decline in the use of heavy fuel oil, consistent with our assumption that natural gas prices will track heavy fuel oil prices - especially in the industrial sector.

3.2.4 Ontario

In Ontario there has been competition between natural gas and electricity for both conversions and new markets, but to a lesser extent than in Quebec. Ontario is the largest regional energy market, accounting for over 35 percent of national demand. It has the largest provincial demand for oil and natural gas, although it consumes a little less electricity than does Quebec. As in the other regions, there is little difference in fuel shares between the low and high oil price cases (Figure 3-5). Electricity and natural gas shares are projected to increase by four percentage points each, to about 20 and 34 percent respectively by 2005, while oil loses eight to ten points, declining by 2005 to about 29 percent of end use demand.

Figure 3-5
End Use Demand by Fuel
Ontario



Source: Appendix Table A3-6

Despite the outlook for lower oil prices, natural gas and electricity maintain a price advantage over oil in the residential sector. Similarly, on an efficiency-adjusted basis, prices of these two fuels are less than oil in the commercial sector. In the industrial sector, efficiency-adjusted natural gas and heavy fuel oil prices are equivalent; both are slightly below electricity prices.

In the residential sector, we project continued conversion from oil - more pronounced in the high oil price case, where oil's share falls from 17 percent in 1984 to 4 percent in 2005 (compared to 8 percent in the low oil price case). In both cases, the natural gas share of residential energy demand reaches 47 percent by 2005. In the high oil price case electricity captures share from oil, reaching 40 percent (versus 35 percent in the low case). The natural gas price maintains an advantage over electricity when adjusted for relative efficiencies but the fuel choice for new housing construction may reflect the relative capital costs of alternate heating systems at least as much as expected fuel costs. For many buildings it is less expensive to install electric heating than natural gas systems; in some instances this may determine the fuel choice for new housing.

Within Ontario's industrial sector, iron and steel together with pulp and paper account for about 45 percent of energy requirements. We expect some penetration of thermomechanical pulping, leading to a shift towards electricity from diesel and hog fuel. Natural gas prices in both cases are very competitive relative to other fuels, which leads to natural gas capturing close to 40 percent of the industrial market by 2005 compared to 35 percent in 1984. Electricity's share remains

around 20 to 22 percent. Increased initiatives by Ontario Hydro or further technological change toward more electricity-intensive processes could increase this fuel's share above the levels we have projected.

3.2.5 Prairie Provinces

Alberta's energy requirements and use of natural gas dominate the fuel profile for the Prairie provinces. Figure 3-6 shows the levels and shares of fuel demand in the two oil price cases. In both Manitoba and Saskatchewan we anticipate an increasing share of electricity in both oil price cases (coming largely from the residential sector). Fuel shares for the region as a whole do not differ substantially between the two cases, both showing a long-run trend of substitution from oil to electricity.

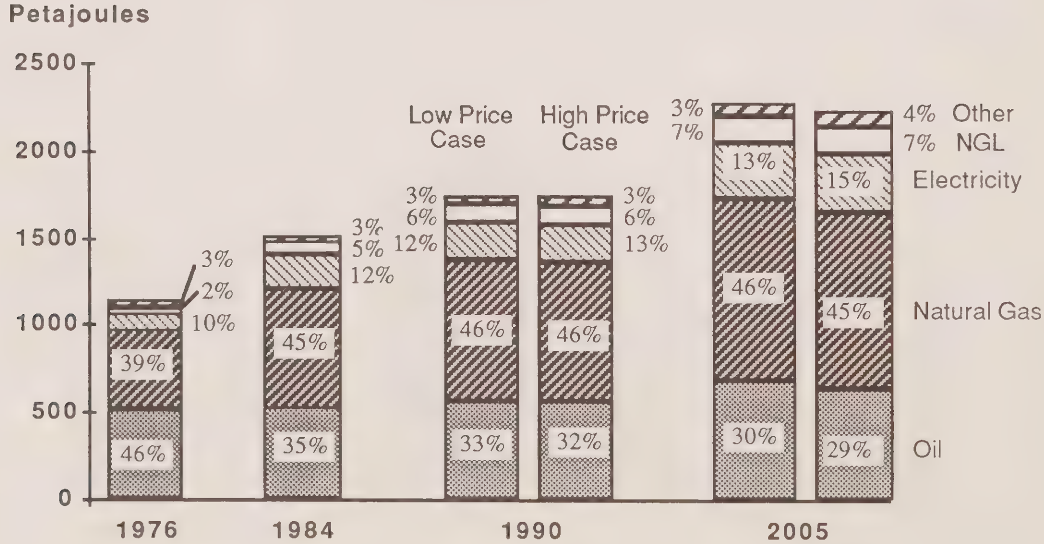
Within Manitoba, in the residential sector there are some minor shifts in shares between the two cases, as the price of electricity relative to oil and gas is more favourable in the high oil price case than in the low. In the high oil price case electricity's share rises from 34 percent in 1984 to 44 percent in 2005 as compared to 39 percent under low oil prices. There is not as much change in Saskatchewan, where natural gas is expected to maintain its current share of one-half of residential demand throughout the projection period. The dominance of natural gas in Alberta's residential sector (72 percent in 1984) is expected to continue throughout the projection horizon in both the high and low oil price cases. Natural gas prices maintain a significant advantage over electricity in this province, and this should reinforce the current choice of natural gas for residential heating.

Natural gas is the major fuel in the industrial sector in both Saskatchewan and Alberta. Electricity accounts for the largest share in Manitoba, reflecting the differences of industrial structure between the provinces. Energy-intensive industries in these provinces include petroleum refining, chemicals, mining, pulp and paper and smelting. In Alberta and Saskatchewan mining dominates the industrial sector and is a large consumer of natural gas, while pulp and paper (which uses hog fuel and diesel fuel oil) and other manufacturing (a major electricity consumer) are large in Manitoba. In all three provinces we anticipate a continued decline in the use of oil. The reduction in oil's share will be split between increases in natural gas and electricity in Manitoba and Saskatchewan, and taken-up by natural gas in Alberta.

3.2.6 British Columbia, Yukon and Northwest Territories

Fuel shares in British Columbia are more similar to those in Ontario than

Figure 3-6
End Use Demand by Fuel
Prairies



Source: Appendix Table A3-6

in Alberta because natural gas does not dominate energy use to the extent that it does in Alberta. Figure 3-7 shows the fuel shares and levels for British Columbia and the two territories.

In the residential sector natural gas currently accounts for the largest share of fuel - 41 percent. In both oil price cases we anticipate that this share will rise to about 47 percent, because oil continues to decline as a fuel for residential heating. Wood is expected to maintain its 10 percent share throughout. Comparative costs of electricity, natural gas, and wood in larger urban areas suggest that further conversions to wood are unlikely to be economic.

We do not include a natural gas pipeline to Vancouver Island in our projections. Should this project proceed, natural gas would probably displace electricity used for heating in the residential market over a period of ten to fifteen years, with the result that the natural gas share would be higher than we have projected.

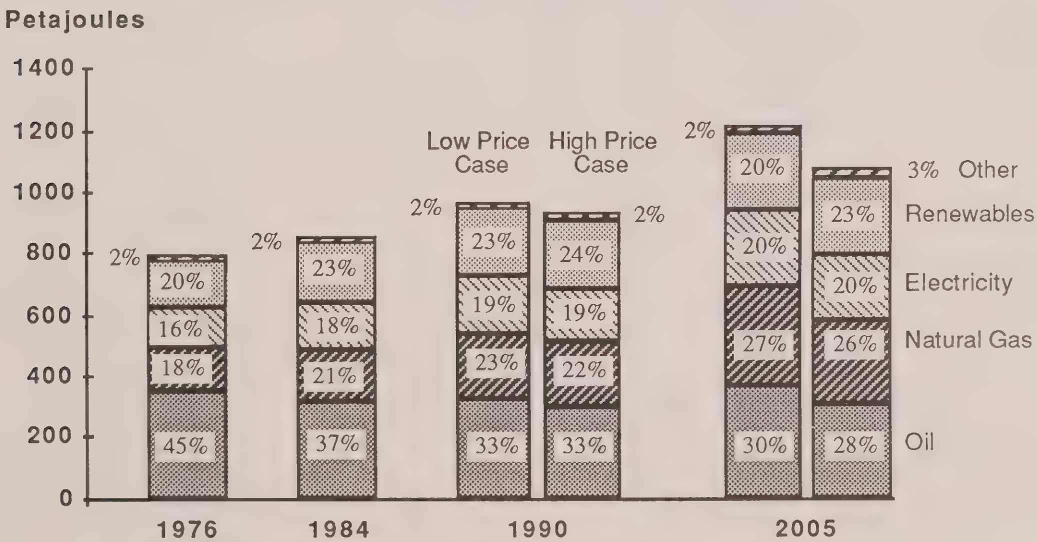
The industrial sector is dominated by pulp and paper, which accounted for 63 percent of industrial energy use in 1984. The next largest energy consumer is smelting and refining, at 8 percent. We do not assume any additional smelting facilities or related major electric power expansions in our projections.

Thermo-mechanical pulping and chemi-thermo-mechanical pulping processes are likely to be adopted in the pulp and paper industry, and we have included some increase in electricity requirements to meet these needs. However, the timing is uncertain and could affect our projections. We also assume that the forestry and pulp and paper industries will face physical constraints to output during the 1990s which will limit their energy demand growth. Physical limitations on production of hog fuel and pulping liquor lead to a gradual decline in their share of industrial energy, from 48 percent in the mid-1980s to 40 and 45 percent by 2005 in the low and high price cases respectively.

Taking these factors and other industrial demand into account, we project a gradual increase in the natural gas share of industrial demand from 16 percent in 1984 to 21 and 23 percent by 2005 in the two oil price cases.

Yukon and the Northwest Territories rely on oil and electricity for all of their energy use. Assuming no major frontier developments and taking into account the settlement pattern of widely-scattered small communities, we do not anticipate any change in fuel mix in the two territories.

Figure 3-7
End Use Demand by Fuel
British Columbia and Territories



Source: Appendix Table A3-6

3.2.7 *Canada*

Though relative prices have become more favourable to oil than they were over the past few years and are projected to remain so, consumers are likely to continue switching away from oil because of uncertainties about oil prices and a concern that they will increase as they have in the past.

Substitution towards electricity, natural gas and, to a lesser extent, other fuels is projected in both cases. We have not assumed any difference in available fuel sources between the two cases. As a result, the difference in fuel shares between the two cases is rather small (see Table 3-8). On the other hand, the volumes of fuels used exhibit more pronounced variations between price cases, resulting from the impact of both income and prices on total energy demand discussed in Section 3.1. (Figure 3-8)

By the year 2005, our projections show an increase in the level of oil consumption relative to 1984, but a drop in its share of total demand. Continued reliance of the transportation sector on oil products, coupled with less rapid vehicle fuel efficiency improvements than in the recent past, are a major factor behind the higher levels of demand at the end of the projection period. Our assumptions of gradual ongoing substitution out of oil and penetration of new markets by electricity and natural gas lead to an increase in these fuels' shares over the period. The outlook of weak price growth for conventional fuels relative to the cost of alternative or renewable energy is the major factor impeding further penetration of these energy sources beyond a 7 to 8 percent share. Our projections for end use demand for NGL largely reflect our outlook for petrochemical feedstock requirements, discussed in Section 3.1.5.

In our projections we assume that residential and commercial consumers of natural gas face the same commodity price as industrial users. The difference in sectoral prices for natural gas reflects only the differences in distribution costs between types of service. The evolution of sectoral prices for natural gas under deregulation is, however, unclear. Our assumptions lead to a significant price advantage for natural gas in the residential and commercial sectors relative to both oil and electricity (in the order of 40 to 60 percent, adjusted for relative efficiencies).

Should natural gas in these two sectors be priced more closely to their competing fuels, we would expect natural gas consumption to be less than we have projected here. Total energy demand in these sectors could also be lower, because of higher energy (natural gas) prices. It is possible that under such assumptions, there would be fewer conversions from oil to natural gas, while electricity could capture a larger share of new markets than we have

Table 3-8

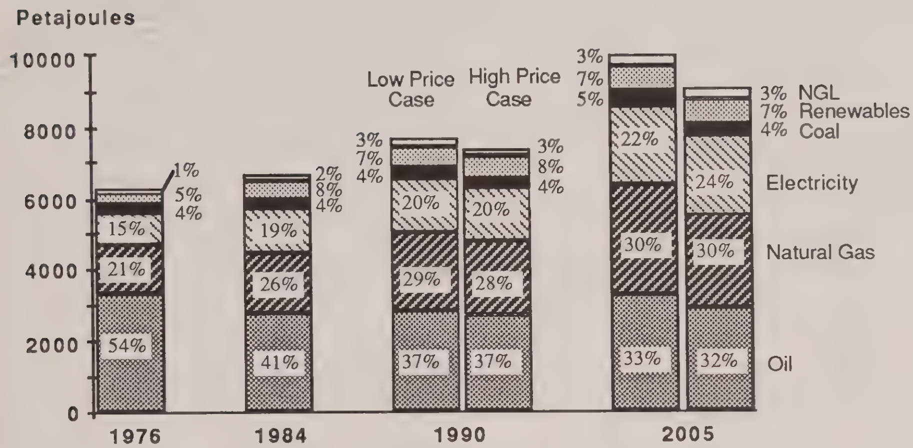
End Use Energy Demand and Fuel Market Shares

	1984	2005		
		Oil Price Case		
		Low	High	Difference [a]
Levels		(Petajoules)		
Electricity	1271	2213	2160	-2
Natural Gas	1743	3034	2682	-12
Oil	2762	3334	2863	-14
Renewables & Steam [b]	510	653	645	-1
Coal	239	450	404	-10
NGL	153	298	303	2
Total	6678	9982	9057	-9
Shares		(Percent)		
Electricity	19	22	24	2
Natural Gas	26	30	30	0
Oil	42	33	32	-1
Renewables & Steam [b]	8	6	7	1
Coal	4	5	4	-1
NGL	2	3	3	0
Total	100	100	100	-

Note: All numbers on this table have been rounded.
[a] Difference for petajoules is high minus low as a percentage of the low oil price case. Difference for shares is the percentage point difference of shares, high minus low.
[b] Includes hog fuel and pulping liquor, wood, wind, solar, municipal solid waste, and steam.

Source: Appendix Table A3-6

Figure 3-8
End Use Demand by Fuel
Canada



Source: Appendix Table A3-6

Table 3-9

Distribution of Primary Oil Demand by Product

(Percent)

	1984	1990		2005	
		Oil Price Case		Oil Price Case	
		Low	High	Low	High
Aviation Fuels	5	6	5	6	6
Motor Gasoline	36	34	35	34	34
Light Fuel Oil and Kerosene	11	9	9	7	5
Diesel Fuel Oil	19	21	21	24	26
Heavy Fuel Oil	11	10	10	9	8
Asphalt	3	4	4	5	5
Other	15	15	15	15	16
Total	100	100	100	100	100

Note: All numbers on this table have been rounded.
Source: Appendix Table A6-16

projected. It is unlikely that there would be conversions out of natural gas, because it would not be more expensive than its competing fuels.

3.3 Primary Energy Demand

3.3.1 Primary Demand For Oil

The largest component of primary oil demand consists of end use requirements for refined products consumed directly by the residential, commercial, industrial and transportation sectors. Oil used to generate steam and electricity, requirements of the energy supply industry to produce and transport oil products, and liquefied petroleum gases produced and used by refiners are also included in primary demand.

Table 3-9 shows the composition of primary oil demand by product for the two cases. There is virtually no difference in product shares between the two cases. In both cases between 1984 and 2005, the decline in demand for light fuel oil in the residential and commercial sectors, and increased use of diesel for transportation, results in the share of light fuel oil and kerosene falling from 11 to 5 percent, while the diesel share rises from 19 to about 25 percent. Appendix Table A6-16 shows the levels of demand by fuel.

Between 1984 and 2005 primary demand for oil is projected to increase at average annual rates of 1.0 and 0.2 percent in the low and high oil price cases respectively. By 2005 the range between the low and high cases is 15 percent or 572 petajoules. This is mainly because of the difference in transportation demand, the largest component of total primary oil demand, which differs by 14 percent or 312 petajoules in 2005. (Table 3-10)

Table 3-10

Primary Demand for Oil by Use

(Petajoules)

	1984	1990 Oil Price Case Low	1990 Oil Price Case High	2005 Oil Price Case Low	2005 Oil Price Case High
Sectoral Demand					
Residential	279	242	216	194	124
Commercial	147	136	128	110	90
Industrial	319	322	301	367	313
Petrochemical	116	98	98	100	100
Transportation	1710	1807	1748	2243	1931
Other non-energy	191	236	233	318	305
Refinery LPG	59	62	58	73	62
Total End Use	2820	2903	2782	3406	2925
Own Use and Conversions [a]					
Energy Supply Industry	230	252	243	302	257
Electricity Generation	62	72	83	116	65
Steam Production	6	2	2	2	2
Butanes Used for Blending	-44	-35	-34	-39	-35
Total Own Use and Conversions	254	291	294	381	289
Total Primary Demand	3075	3194	3076	3787	3214

Note: All numbers on this table have been rounded.
[a] Includes refinery LPG own use.

Source: Appendix Table A3-3

Table 3-11

Primary Demand for Natural Gas

(Petajoules)

	1984	1990 Oil Price Case Low	1990 Oil Price Case High	2005 Oil Price Case Low	2005 Oil Price Case High
End Use	1744	2195	2079	3034	2682
To generate electricity	67	44	51	71	68
Net Sales	1811	2239	2130	3105	2750
Pipeline fuel and loss	127	183	174	182	156
Reprocessing fuel	11	17	16	14	12
Primary Demand	1949	2438	2319	3302	2918

Note: All numbers on this table have been rounded.

Source: Appendix Table A3-3

3.3.2 Primary Demand for Natural Gas

In addition to demand for end uses, primary demand for natural gas includes requirements for thermal electricity generation, pipeline fuel use and loss and reprocessing fuel. (End use plus fuel for electricity generation is also termed "net sales"). Primary demand is dominated by end use requirements (90 percent in 1984), and therefore reflects the major uncertainties relating to future end use demand. (See Table 3-11) Primary natural gas demand grows on average at rates of 2.5 percent and 2.0 percent annually over 1984-2005, in the low and high oil price cases respectively, compared to 2.7 percent and 2.0 percent for end use demand.

Natural gas is used to generate electricity in Ontario, Saskatchewan, Alberta and British Columbia (see Chapter 4). This use of natural gas is projected in the low price case to reach 12 petajoules in Ontario, 4 petajoules in Saskatchewan, 34 petajoules in Alberta and 22 petajoules in British Columbia, in 2005. In the high price case the levels are similar. These projections depend on end use demand for electricity and our expectations of how that electricity demand is met through the various sources of generation (discussed in Chapter 4).

Pipeline fuel use and loss includes fuel to transport and distribute natural gas for domestic and export requirements. The pattern in the projection period reflects a peaking of fuel requirements for natural gas exports in 1989-90 at about 65 petajoules, falling to zero as the terms of currently authorized exports expire (natural gas export projections are discussed in Chapter 5). In 2005 in the low oil price case 127 petajoules

are required for transportation and 55 petajoules for distribution of natural gas. In the high oil price case 107 petajoules are used by 2005 for transportation and 49 petajoules for the distribution of natural gas.

3.3.3 *Primary Demand For Natural Gas Liquids*

For purposes of primary demand analysis, natural gas liquids (NGL) are defined to include propane, butanes and ethane. Propane and butanes may be produced by gas plants or refineries, while ethane is a by-product of natural gas. Table 3-12 shows primary demand for these natural gas liquids in the two oil price cases. As with other hydrocarbons most primary demand for NGL derives from end use requirements. Most end use demand is for petrochemical feedstock (50-60 percent of end use demand for NGL). Refinery liquefied petroleum gases - propane and butanes produced by refineries - are treated as part of primary demand for oil, leaving primary demand for ethane and gas plant NGL, as shown in Table 3-12.

3.3.4 *Primary Demand for Coal*

Unlike other fuels, end use demand represents only a small share of primary demand for coal. Its major use is in the generation of electricity, largely in Ontario, Alberta, Saskatchewan, and Nova Scotia. Coal is used by the iron and steel sector in the form of coke, and this conversion represents the second largest demand for the primary fuel (Table 3-13).

Between 1984 and 2005, primary demand for coal is expected to increase at average rates of 2.9 percent and 2.6 percent annually under the low and high oil price cases. In the low price case this reflects a rapid increase in coal requirements to generate electricity, which more than double from 763 petajoules in 1990 to over 1600 petajoules by 2005. In 2005, coal used for electricity generation in the Atlantic region reaches 428 petajoules (373 in the high), in Ontario 544 (415) petajoules, in Saskatchewan 213 (223) petajoules and in Alberta 451 (564) petajoules.

Table 3-12

Primary Demand for Natural Gas Liquids

(Petajoules)

	1984	1990		2005	
		Oil Price Case Low	High	Oil Price Case Low	High
End Use Demand	153	226	227	298	303
Propane and Butanes	99	144	146	172	177
Ethane	54	81	81	126	126
Own Use and Conversions	52	60	59	67	64
Energy Supply Industry	8	24	24	28	29
Butanes Used for Blending	44	35	35	39	35
Sub-total	205	286	286	365	367
Less Refinery LPG [a]	65	84	81	99	88
Primary Demand for Ethane and Gas Plant NGL	140	202	205	267	279

Note: All numbers on this table have been rounded.
[a] End use demand assumed to be met by refineries.

Source: Appendix Table A3-3

Table 3-13

Primary Demand for Coal

(Petajoules)

	1984	1990		2005	
		Oil Price Case Low	High	Oil Price Case Low	High
End Use Demand [a]	48	68	63	99	89
Electricity Generation	913	763	758	1644	1585
Steam Generation	5	1	1	1	1
Other Conversions and Own Use	1	6	6	10	9
Coal to Coke Conversion	200	261	253	368	330
Primary Demand	1167	1100	1081	2123	2014

Note: All numbers on this table have been rounded.
[a] Includes coal, coke and coke oven gas use.

Source: Appendix Table A3-3

Chapter 4
Electricity

In this chapter we assess the principal implications of our electricity demand scenarios for new generating capacity and for fossil fuels, hydro and nuclear resources required to generate electricity. We also assess the prospects for electricity trade between provinces and with the United States.

To arrive at the total demand for electrical energy in each province, the petajoule end use demand estimates from Chapter 3 are converted to gigawatt hours of electrical energy. To this are added the estimated utilities' own use and losses and expected levels of firm interprovincial sales and exports. This demand for electrical energy, along with information from the utilities' generation expansion plans, is first used to estimate the generating capacity that would be required in each province and the quantities of primary energy resources (hydro, nuclear and fossil fuels) needed to meet the firm electricity demand in each year. Having thus determined the plan of new capacity additions and the surplus energy capability, we then estimate the potential sale of surpluses on the interprovincial and export markets.

In the electricity supply industry, the units used for electrical energy and power (i.e. the capacity used to produce electricity) are multiples of kilowatt hours (kW.h) and kilowatts (kW) respectively. The multiples of these units that are used in this report are gigawatt hours (GW.h), terawatt hours (TW.h), megawatts (MW) and gigawatts (GW). (See Appendix Table A1-2).

Most Canadians purchase their electricity from utilities. The major utilities in most of the provinces are provincially-owned except for Prince Edward Island and Alberta where they are investor-owned. In the Territories the utility is federally-owned. These utilities have the overall responsibility for ensuring that there are adequate supplies of electricity to reliably meet their firm commitments.

Since planning and building new facilities may take a decade or more, utilities routinely forecast their customers' requirements for periods of fifteen to twenty years. This sets a framework for the orderly planning and construction of new generating plants and transmission facilities, and the acquisition of the required fuels and other resources needed to meet the anticipated demand.

Apart from the utilities, some industries as well as individuals generate their own electricity from a wide variety of energy sources.

Except for Alberta, the provinces adjacent to the United States have transmission links over which they can import and export electricity. The Alberta system is linked to British Columbia and through it to the United States.

Until 1985, provincial utilities generally planned for the construction of generating capacity in order to meet only their anticipated service area needs. Inadvertent surplus generating capability, which resulted when anticipated loads did not materialize or when incremental capacity additions were larger than the short-term increases in demand, was made available for sale to neighbouring utilities. The practice has been to offer these surpluses first to neighbouring Canadian utilities and secondly to utilities in the United States. Sales of these kinds of surpluses form the bulk of interprovincial transactions and of currently licensed electricity exports. Exceptions are New Brunswick's firm export of oil-generated electricity from Coleson Cove, which ends in 1986, exports under Lepreau I unit participation agreements and a firm power export from Manitoba predicated on the pre-building of hydro capacity which was licensed by the National Energy Board in 1985.

Throughout this chapter we have segregated export sales into classifications which reflect the level of service provided and, generally, the price paid. The highest level of service is provided by long term firm sales of capacity power and energy. At the other extreme are interruptible energy sales scheduled hour by hour to permit fuel economy on the purchasing system. In reality there are many different kinds of transactions which form an almost continuous spectrum of services between firm and interruptible sales.

In addition, we have made a clear distinction between those exports that are currently licensed by the National Energy Board and new sales not currently licensed, termed potential, which we assume will take place in the future in order to enable realistic projections to be made. Virtually all existing export licences terminate within the forecast period but it is unlikely that exports will end.

To project interruptible export sales we employ a computer model to simulate the planning and annual operation of the major provincial utilities. The model is used to schedule capacity additions, taking into account required reserve capacity, so that the total peak demand and energy requirements, including interprovincial firm commitments and projected firm potential exports, are met every year.

Surplus production capability is then determined as the difference

between projected total annual average capability and total firm energy requirements. The resulting surplus is then assumed to be available for out-of-province sales on an interruptible basis. In accordance with standard utility trading practices, which aim to maximize the economic gains from interconnected operation, it was assumed that the energy surpluses would generally be sold on the basis of transactions between markets with the lowest and highest incremental costs.

We estimate that surplus hydro and nuclear energy, because of its low incremental production cost, will find ready markets. For this reason we expect that all such surpluses will be sold up to the level of existing and planned interconnections. Coal-generated electricity, particularly from Ontario, although less attractive in price than hydro or nuclear, is nonetheless expected to retain some price advantage over older, smaller, less efficient units burning oil or coal in the United States. This is particularly true in the high oil price case.

The small amounts of surplus oil- and gas-fired capability are not expected to be saleable. This is because of the substantial amount of existing surplus capability of this type in the United States. The sole exception to this is in New Brunswick where a small oil-based export ends in 1986.

In addition to the current pattern of interprovincial and export transactions, we have included for Quebec, Manitoba and British Columbia potential additional exports of firm hydro capacity and energy and have assumed that hydro plants will be pre-built for the purpose. In New Brunswick we assume a continuation of the currently licensed nuclear export and an additional sale of coal capacity and energy starting in the mid-1990s. A more detailed review of these assumptions is contained in the provincial sub-sections.

The inclusion of these additional not-yet-licensed potential exports, although reflecting the intentions of utilities, does not prejudge the desirability or feasibility of exporting electricity. All such exports are subject to licensing by the National Energy Board.

4.1 Total Electricity Demand

Table 4-1 contains our electricity demand outlooks expressed in terawatt hours. These are converted from the end use petajoule values presented in Section 3.1 of the report using a conversion factor of 3.6 petajoules per terawatt hour.

Table 4-1 also contains our estimates of the annual peak power demand (i.e. the highest level of power demanded in the year) for each province and region. These have been calculated from the energy demand outlooks by projecting provincial load factors (the ratio of average to peak load) based on historical data and on our expectations with regard to peak load management by utilities. At present, load factors typically range between 60 and 70 percent. We assume that in some provinces, efforts to shift consumption from peak to off-peak times (peak load management) will cause load factors to gradually increase over the study period.

It is useful to recall that our electricity demand projections are strongly tied to our outlooks for economic activity in each province. In the low price case, increased economic activity results in an increased demand for electricity and other energy forms in central Canada. Regions which depend on oil exploration and development show slower rates of electricity demand growth. Conversely, in the high price case there is a lower growth rate of electricity demand in central Canada but relatively faster growth in Alberta, Newfoundland, Nova Scotia and to some extent the Territories. For Canada as a whole, we project growth in electricity demand at an average annual rate of 2.8 percent (low price case) and 2.6 percent (high price case) until 1990. These rates slow to 2.6 and 2.5 percent for the low and high price cases respectively between 1990 and 2005.

4.2 Generating Capacity and Electrical Energy Production by Region

Electricity demand varies with the time of day and season. The annual peak demand recorded by Canadian utilities usually occurs in December or January. Electricity producers require sufficient generating capacity to meet this peak demand. Sound engineering practice also requires the carrying of reserve generating capacity to allow for possible equipment breakdowns and maintenance and to provide for reliable and continuous service to customers. Some utilities require a larger reserve margin than others, depending on individual operating conditions.

Each generating unit is capable of producing a specific amount of energy, on average, each year. There are several different types of generating units, each designed for a particular type of service corresponding to the amount of time the unit may be required to operate. For instance, a base load nuclear unit may operate 85 percent of the time, producing considerable energy, while an oil-fired peaking unit of the same capacity may operate only

Table 4-1

Electricity Demand [a]

Electrical Energy Demand

	Energy Demand (Terawatt hours)			Rate of Growth (Percent per year)		Percent Change	
	1984	2005		1984 to 2005		1984 to 2005	
		Low Price Case	High Price Case	Low Price Case	High Price Case	Low Price Case	High Price Case
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Newfoundland	9.64	15.48	19.65	2.3	3.4	61	104
Prince Edward Island	0.55	0.88	0.89	3.3	3.0	60	60
Nova Scotia	7.27	14.05	13.15	2.3	2.3	93	81
New Brunswick	10.52	22.03	20.15	3.6	3.2	109	92
Quebec	135.31	230.37	221.94	2.6	2.4	70	64
Ontario	118.38	215.89	205.44	2.9	2.7	82	74
Manitoba	15.24	27.90	27.18	2.9	2.8	83	78
Saskatchewan	11.82	20.29	21.16	2.6	2.8	72	79
Alberta	31.20	48.37	57.08	2.1	2.9	55	83
British Columbia	45.60	72.50	65.00	2.2	1.7	59	43
Yukon	0.25	0.28	0.35	0.5	1.6	11	40
Northwest Territories	0.52	0.84	0.80	2.3	2.1	61	54
Total Canada	386.30	668.88	652.79	2.7	2.5	73	69

Peak Demand [b]

	Peak Demand (Megawatts)			Rate of Growth (Percent per year)		Percent Change	
	1984	2005		1984 to 2005		1984 to 2005	
		Low Price Case	High Price Case	Low Price Case	High Price Case	Low Price Case	High Price Case
	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Newfoundland	1698	2577	3238	2.0	3.1	52	91
Prince Edward Island	103	167	169	2.3	2.4	62	64
Nova Scotia	1388	2687	2438	3.2	2.7	94	76
New Brunswick	1989	4291	3872	3.7	3.2	116	95
Quebec	26761	42454	39636	2.2	1.9	59	48
Ontario	21379	35305	33601	2.4	2.2	65	57
Manitoba	2829	5704	5508	3.4	3.2	102	95
Saskatchewan	2278	3850	4016	2.5	2.7	69	76
Alberta	5475	8505	10058	2.1	2.9	55	84
British Columbia	8250	13101	11730	2.2	1.7	59	42
Yukon	53	49	62	-0.4	0.8	-7	17
Northwest Territories	193	190	183	-0.1	-0.3	-2	-5
Total Canada	72396	118880	114511	2.4	2.2	64	58

Note: The numbers in this table have been rounded.
[a] Excludes export sales.
[b] Peak demand is the algebraic sum of non-coincident loads.

5 percent of the time, producing little energy on an annual basis.

As described earlier, short-term incidental surpluses may result when projected loads fail to materialize or when large plants are built and the short-term increase in energy capability exceeds the annual demand increment.

We expect that there will be a modest increase in generating capacity associated with co-generation and non-conventional resources particularly at industrial facilities. We do not, however, anticipate that these sources will account for an appreciable portion of overall generating capacity in Canada.

Industrial generating capacity of various types accounted for approximately 6000 MW or about 6 percent of total generating capacity in 1985. Such generation is expected to amount to approximately 7000 MW, about 5 percent of total capacity, in the year 2005.

Provincial Projections

In each province, the plans for future generation expansion are based on the use of different primary resources. In Alberta, for example, expansion plans are largely based on the development of local coal deposits, while in Quebec they are based on hydro resources.

Utilities plan their generating system expansion on a provincial basis based on load forecasts and using an appropriate mix of differing generating technologies and primary resources. For this reason, each province and territory is dealt with separately in this section. Each sub-section contains a short review of the low and high price case load outlooks, a description of the plans by which the loads are projected to be met and a discussion of the out-

of-province purchases and sales which we have projected. The chapter concludes with a review of the major implications of our two cases for each fuel or technology type, for all of Canada.

Table 4-2 shows the relative magnitude of the various provinces' generating capacity and actual energy generation for the year 1984, the latest year for which complete statistics have been compiled. It should be noted that the Newfoundland and Labrador statistics contain a 5200 megawatt component from Churchill Falls, most of which is sold to Hydro-Quebec on a long-term basis.

Tables 4-3 through 4-14 provide our projections of capacity and production by province and territory. More detailed information can be found in Appendix Tables A4-4 and A4-5. In all these tables the numbers in the rows entitled "Remaining Capacity" include the required reserve capacity and should not be construed to be surpluses which may be available for sale or which are truly surplus to requirements.

Newfoundland and Labrador

In Newfoundland and Labrador, we project that the load will grow from a level of 9.7 terawatt hours in 1984 to 15.5 and 19.7 terawatt hours in 2005 for the low and high price cases respectively. This corresponds to annual growth rates of 2.3 and 3.4 percent.

The Newfoundland and Labrador system is split, with over 95 percent of the load concentrated on the island and most of the major hydro resources in Labrador on the mainland.

On the island, most of the economically developable hydro sites have been built and, as a result, the island system is now increasingly reliant on its oil generation; oil-fired capacity currently supplies about 20 percent of the island's total electrical energy demand. As loads increase, new generating capacity is likely to be required around 1990. Consistent with the province's published intentions, we assume that a major submarine cable link to the mainland will be built to satisfy future island needs. We estimate 1995 to be a reasonable completion date given the large investments that this project would entail and the considerable lead time required for negotiating agreements and constructing the line. In the interim, increases in island loads will have to be met by installing combustion turbine units and by burning increasing amounts of fuel oil at Holyrood. After 1995, all new developments will be hydro-based in our scenario and oil consumption will sharply diminish.

Table 4-2

Generating Capacity and Energy Production by Province and Territory in 1984

	Capacity		Energy	
	Percent	Megawatts	Percent	Gigawatt Hours
Newfoundland	7.8	7048	10.7	45649
Prince Edward Island	0.1	123	0.0	2
Nova Scotia	2.3	2111	1.7	7235
New Brunswick	3.7	3352	2.9	12395
Quebec	28.5	25757	28.7	122178
Ontario	27.8	25164	28.4	120605
Manitoba	4.5	4042	5.1	21487
Saskatchewan	2.8	2515	2.7	11542
Alberta	8.0	7202	7.3	31159
British Columbia	14.2	12800	12.3	52378
Yukon	0.1	122	0.1	254
Northwest Territories	0.2	191	0.1	523
Total Canada	100.0	90427	100.0	425407

Note: The numbers in this table have been rounded.

Source: Appendix Tables A4-4 and A4-5

While the Labrador load is small, less than 5 percent of the total provincial load, there is a large 5200 megawatt hydro plant at Churchill Falls. Most of its output is sold to Quebec under a long term contract. We assume that Labrador loads will continue to be met mainly by part of the output of Churchill Falls. By 1995, a new hydro plant is projected to be built at Gull Island in Labrador to supply the island via the new cable. In the event that the cable project is delayed or deferred, additional fossil fuel-fired capacity would be required on the island.

Prince Edward Island

The demand projections for Prince Edward Island are very similar for both price cases, starting at 552 gigawatt hours in 1984 and growing to about 900 gigawatt hours in 2005, an annual growth rate of about 2.3 percent.

Although Prince Edward Island currently has sufficient oil-fired

Table 4-3

Generation of Electricity in Newfoundland and Labrador

	1984	1990 Low Price Case	1990 High Price Case	2005 Low Price Case	2005 High Price Case
Generating Capacity (MW)	7048	7175	7325	8990	9090
Domestic Peak Demand	1698	1981	2201	2577	3238
System Peak Demand	6448	6731	6951	7327	7988
Remaining Capacity	600	444	374	1663	1102
Percent of Domestic Peak[a]	35	22	17	65	34
Energy Production (GW.h)	45649	46921	48194	57036	57606
Hydro	44775	45501	45488	56743	56761
Coal	0	0	0	0	0
Nuclear	0	0	0	0	0
Other	874	1420	2706	293	845
Domestic Consumption (GW.h)	9636	11098	12371	15480	19650
Net Interprov. Transfers out (in)	36013	35823	35823	41556	37956
Net Exports	0	0	0	0	0

[a] Remaining Capacity is expressed as a percentage of domestic peak for Newfoundland and Labrador rather than of system peak.

Table 4-4

Generation of Electricity in Prince Edward Island

	1984	1990 Low Price Case	1990 High Price Case	2005 Low Price Case	2005 High Price Case
Generating Capacity (MW)[a]	143	158	158	203	203
Domestic Peak Demand	103	126	126	167	203
System Peak Demand	103	126	126	167	169
Remaining Capacity	40	32	32	36	34
Percent of System Peak	39	25	25	22	20
Energy Production (GW.h)	2	5	4	5	1
Hydro	0	0	0	0	0
Coal	0	0	0	0	0
Nuclear	0	0	0	0	0
Other	2	5	4	5	1
Domestic Consumption (GW.h)	552	660	660	880	890
Net Interprov. Transfers out (in)	(550)	(655)	(656)	(875)	(889)
Net Exports	0	0	0	0	0

[a] Takes into account capacity purchased from New Brunswick of 20 megawatts in 1984, 35 megawatts in 1990, and 80 megawatts in 2005.

generating capacity to satisfy its own needs, for economic reasons it has been obtaining almost all of its energy from New Brunswick via a submarine cable interconnection. We assume that this interconnection will be modified so that more of the 200 megawatt nominal capacity of the submarine cable will be available for use. Accordingly, we expect that New Brunswick will continue to supply virtually all of the energy and all of the additional capacity needs of Prince Edward Island during the entire study period.

In the low price case, more of the purchases from New Brunswick are expected to be from oil-fired generation, while for the high price case, new purchases are assumed to be from coal-fired plants.

Nova Scotia

In 1984, the provincial demand for electricity in Nova Scotia was 7.3 terawatt hours. We anticipate that this will grow to 14.1 and 13.2 terawatt hours by 2005 for the low and high price cases respectively. This corresponds to annual load growth rates of 3.2 and 2.9 percent.

The province's generating capacity mix is currently about 40 percent coal, 43 percent oil and 17 percent hydro.

We assume that by 1989, Nova Scotia will complete its conversion of major oil-fired plants to coal, and that all new large capacity additions will burn coal. This reflects the provincial policy of developing its indigenous coal resources.

Because of its high relative capital cost, we assume that no further development of tidal power will take place within the study period although the 20 megawatt Annapolis Royal plant, completed in 1984, is a success.

We expect that new generating capacity will be required by the mid-1990s. Consistent with recent announcements by the province, we assume that the next major additions will be coal units, each with a capacity of 150 megawatts, sited in Cape Breton. The timing of the additions will be determined by provincial load growth.

Nova Scotia and New Brunswick have traded in electricity on an interruptible basis for some time. In general, the net energy flows are relatively small in the direction of Nova Scotia and correspond to economy energy transactions and the sale of some surplus hydro energy by New Brunswick, particularly during the spring when river flows in that province are at their peak. We assume that these transactions will continue at a level similar to those in the last few years. The province does not currently export electricity and we have not included any exports within the study period.

New Brunswick

We project that by 2005 in-province demand in New Brunswick will grow to about 22 terawatt hours in the low price case and to 20 terawatt hours in the high, from the 1984 level of 10.5 terawatt hours. This translates into an annual load growth rate of about 3.1 percent.

The province currently has a mix of about 26 percent hydro, 47 percent oil, 9 percent coal and 18 percent nuclear capacity (counting all of the capacity of the Point Lepreau nuclear plant).

New Brunswick has a large oil plant at Coleson Cove which we expect to be converted to coal by 1991. Following that, we anticipate that further major capacity additions will be coal-based, starting first with additional units at Coleson Cove. These assumptions are based on our understanding of the utility's current intentions.

In addition to its own capacity, New Brunswick has a total of about 1000 megawatts of interconnection capacity with Quebec. This is used to make interruptible hydro energy purchases equivalent to about one half of the provincial energy demand. This energy is used partly to displace electricity generated from fossil fuels and is partly resold. Some of the purchased hydro energy, along with some of New Brunswick's own surplus fossil fuel and hydro-generated energy is sold on an interruptible basis to Nova Scotia and Prince Edward Island; but most of it is exported to New England. Purchases from Quebec are expected to continue, but at a lower rate in the 1990s. This is because of the lower levels of expected hydro surpluses on the Quebec system as well as increased markets for those surpluses in the United States. As well, it is likely that New Brunswick will continue making interruptible energy sales to Nova Scotia and Prince Edward Island.

In addition to economy energy, New Brunswick is expected to sell small blocks of firm power and energy from specific plants to Prince Edward Island as loads grow in that province. (This type of sale is termed "unit participation".)

New Brunswick's only nuclear plant (Lepreau I) is a 630 megawatt unit at Point Lepreau of which about 330 megawatts is dedicated to firm unit participation exports until the early 1990s. New Brunswick is considering the construction of a second 630 megawatt nuclear unit at Point Lepreau; however, as dis-

Table 4-5

Generation of Electricity in Nova Scotia

	1984	1990		2005	
		Low Price Case	High Price Case	Low Price Case	High Price Case
Generating Capacity (MW)	2111	2185	2185	3275	2915
Domestic Peak Demand	1388	1598	1532	2687	2438
System Peak Demand	1388	1598	1532	2687	2438
Remaining Capacity	723	587	653	588	477
Percent of System Peak	52	37	43	22	20
Energy Production (GW.h)	7235	8130	7910	13839	12938
Hydro	1034	1072	1072	1072	1072
Coal	4878	6185	6076	10546	9684
Nuclear	0	0	0	0	0
Other	1323	873	762	2221	2182
Domestic Consumption (GW.h)	7266	8330	8110	14039	13138
Net Interprov. Transfers out (in)	(31)	(200)	(200)	(200)	(200)
Net Exports	0	0	0	0	0

Table 4-6

Generation of Electricity in New Brunswick

	1984	1990 Low Price Case	1990 High Price Case	2005 Low Price Case	2005 High Price Case
Generating Capacity (MW)	3352	3448	3448	5748	5298
Domestic Peak Demand	1989	2571	2485	4291	3872
System Peak Demand	2372	2836	2750	4851	4432
Remaining Capacity	980	612	698	897	866
Percent of System Peak	41	22	25	18	20
Energy Production (GW.h)	12395	15082	14973	27650	25425
Hydro	3121	2806	2879	2806	2879
Coal	1594	4644	4527	19172	16284
Nuclear	5007	4503	4745	4503	4745
Other	2673	3129	2822	1169	1517
Domestic Consumption (GW.h)	10515	12934	12492	22030	20138
Net Interprov. Transfers out (in)	(3759)	(5144)	(5144)	(2925)	(2911)
Net Exports	5639	7292	7625	8545	8198

cussions are at an early stage, we have not included it in our outlooks. We assume that exports from Lepreau I will be re-negotiated to continue until the end of the study period. In addition, we include in our outlooks 250 megawatts of unit participation export sales expected to commence in the mid-1990s from a new coal unit. This sale will be coupled with an expansion of the province's transmission interconnections with New England. New Brunswick has adopted the unit participation or shared unit approach to enable the province to build larger, more efficient units than might otherwise be tolerable on a relatively small system.

Quebec

In 1984 the in-province load was 135.3 terawatt hours, of which about 27 percent was supplied from purchased energy generated at Churchill Falls in Labrador. The load is projected to grow to 230.4 and 221.9 terawatt hours in 2005 for the low and high price cases respectively. The corresponding annual load growth rates are 2.6 and 2.4 percent.

Quebec's current generating capacity mix is about 94 percent hydro, 2 percent nuclear and 4 percent oil. Additional details are given in Table 4-7. To meet only the growing in-province demand, and not make new firm export sales, Quebec would require additional peaking capacity in the 1990s but no major base load additions until close to the year 2000. This additional peaking capacity would be a mix of hydro and combustion turbine units.

Quebec has a large reservoir storage capacity and is able to regulate its hydroelectric production to even out fluctuations due to changes in annual rainfall. This and the ability to store large amounts of energy from year to year, give Quebec special capabilities to supply its own loads and make a wide variety of transactions with neighbouring systems.

In addition to meeting the provincial loads as previously discussed, we assume that Quebec will advance the construction of base load hydro plants in order to make potential export sales. This is consistent with the utility's most recently published development plans and with an export application currently before the National Energy Board. These exports entail the construction of base load hydro plants to come on stream early in the 1990s in excess of the peaking capacity likely to be sufficient to meet in-province needs. We expect that the recently completed 690 megawatt export line to New England will be expanded to 2000 megawatts by 1990 to permit the additional export. In addition to this line, Quebec has a major international interconnection with New York.

By the end of the 1990s we anticipate that the need for new capacity in the United States will give Quebec the opportunity to export additional firm power and energy. Again, we are projecting that these sales will entail the advancement of generating plants as required. These additional potential exports are expected to total about 1500 megawatts by 2005.

In Canada, Quebec has major interconnections with Newfoundland and Labrador, New Brunswick and Ontario. We assume that purchases from Churchill Falls in Labrador will continue as contracted. Sales to New Brunswick have almost always been at a level close to the physical limit of the interconnections. We expect that this will continue until

the early 1990s. Thereafter, the sales will vary depending on the amount of surplus energy available in Quebec. In the low price case the sales to New Brunswick decline by the mid-1990s to less than half their 1985 level. In the high price case, because of larger short-term surpluses in Quebec, this decline is not so marked.

We anticipate that sales to Ontario will fall from current levels by the early 1990s and then stabilize at about half of the level of current transactions. For Quebec, Ontario is a less lucrative market for economy energy sales because of its reliance on nuclear and efficient coal-burning plants. We have not included in our forecast any new firm sale to Ontario.

Ontario

We project that by 2005, the in-province demand for electricity will grow to 215.9 and 205.4 terawatt hours, for the low and high price cases respectively, from the 1984 level of 118.4 terawatt hours. This corresponds to annual growth rates of 2.9 and 2.7 percent.

Ontario's mix of generating capacity is currently about 26 percent hydroelectric, 37 percent nuclear, 34 percent coal, and 3 percent gas and oil.

Ontario has interconnections with both Manitoba and Quebec, and with New York and Michigan through which it has access to markets in other states. In Canada, Ontario purchases energy but little capacity from Quebec and Manitoba. We assume that purchases will continue but at somewhat lower levels from Quebec, as discussed above.

As Ontario's loads grow, new generating facilities will be required by the mid-1990s. Consistent with a recent provincial decision, the Darlington nuclear plant is to be completed on schedule by 1992. Following Darlington, and within the range of the development options currently being considered, we are assuming that Ontario will opt for a mixed strategy. Ontario will first build a few small hydro facilities and put back into service some of its units now in storage. Secondly, a load management program will be implemented to decrease the demands at peak time. Finally, new coal and nuclear plants will be built as needed. Even in the lower of the two load growth cases, Ontario's needs grow by the equivalent of about one Darlington unit (about 900 megawatts) each year.

The anticipated mix of new facilities are slightly different for the two price cases. In the low price case, the expansion plan is more coal-based, and Ontario's Lennox oil-fired plant would be returned to service. In both cases nuclear development is put off until about the end of the century. In the high price case, we assume that Lennox will not be returned to service because the incremental cost of production from oil will likely be higher than the total cost of coal-fired generation. The result is that coal units will be built sooner and that nuclear developments will resume a little earlier than in the low price case.

Ontario is considering the purchase from Quebec and Manitoba of large blocks of firm power as an alterna-

Table 4-7

Generation of Electricity in Quebec

	1984	1990		2005	
		Low Price Case	High Price Case	Low Price Case	High Price Case
Generating Capacity (MW)	30507	33094	33094	48802	45852
Domestic Peak Demand	26761	28656	27672	42454	39636
System Peak Demand	26761	28656	27872	44154	41336
Remaining Capacity[a]	3746	4438	5222	4648	4516
Percent of System Peak	14	15	19	11	11
Energy Production (GW.h)	122178	158877	159347	212464	207934
Hydro (net)[b]	118535	154137	154607	206455	203083
Coal	0	0	0	0	0
Nuclear	3422	4415	4415	4415	4415
Other	221	325	325	1594	436
Domestic Consumption (GW.h)	135310	157650	154620	230370	221940
Net Interprov. Transfers out (in)	(24374)	(27823)	(26823)	(34556)	(30956)
Net Exports	11242	29050	31550	16650	16950

[a] Takes into account capacity purchased from Churchill Falls of 4750 megawatts in 1984, 4750 megawatts in 1990, and 4750 megawatts in 2005.
[b] Hydro generation includes losses attributable to pumped storage hydro plants.

tive to building some additional plants. These discussions are at an early stage and we have not included any such large purchases from Quebec or Manitoba in our outlooks.

Historically, Ontario has been Canada's largest exporter of electricity, selling mostly coal-generated electricity to United States utilities dependent on oil and less efficient, older coal-based capacity. In both outlooks we expect those exports to continue, but in the low price case they are projected to decline to half of current levels as a result of competitive pressure from oil generation in the United States, not recovering until oil prices increase somewhat later in the 1990s. In the high price case the decline is less pronounced and the recovery of exports occurs sooner. In addition to coal, we project that some surpluses of nuclear energy will be sold, as available. Surplus nuclear energy is particularly marketable because of its low incremental cost of production.

Manitoba

In 1984, the in-province demand for electricity in Manitoba was 15.2 terawatt-hours. By 2005, the demand is expected to grow to 27.9 and 27.2 terawatt hours for the low and high price cases respectively, corresponding to an annual load growth rate of about 2.9 percent.

Manitoba's current generating capacity mix is about 87 percent hydro, 8 percent coal, with the balance being other fuel types.

Given Manitoba's abundant undeveloped hydro resources, we expect that all major new developments will be hydro-based. To meet the provincial demand, Manitoba would not have had to build a new major plant until the mid-1990s. However, the province has advanced the completion of the 1200 megawatt Limestone hydro plant to 1991 in order to make a licensed 500 megawatt firm power export. This export, the first of its kind in Canada, is scheduled to begin in 1991 and to end in 2003. In addition to this sale, and consistent with recent announcements by the province, we assume that another potential firm power export of 550 megawatts will be made from 1996 to 2005. This sale will entail the construction of a new international interconnection and the further advanced construction of generating plants.

Manitoba is interconnected with Ontario and Saskatchewan but transactions with these provinces have been modest in comparison with exports. In the case of Saskatchewan, this results from its abundant supply of inexpensive lignite coal and, in Ontario, to the limited size and long length of the transmission links between its eastern system and Manitoba. For these reasons, we are assuming that transactions with these provinces will continue at levels similar to those of the recent past.

Saskatchewan

By 2005, we project that the in-province electricity demand will grow to 20.3 and 21.2 terawatt hours in the low and high price cases respectively, from the 1984 level of 11.8 terawatt hours. This corresponds to annual growth rates of about 2.6 and 2.8 percent respectively.

The province's current mix of generating facilities is about 56 percent coal, 30 percent hydroelectric and 14 percent gas.

Saskatchewan is largely self reliant in capacity and electrical energy. It conducts only modest levels of transactions with Manitoba,

Table 4-8

Generation of Electricity in Ontario

	1984	1990		2005	
		Low Price Case	High Price Case	Low Price Case	High Price Case
Generating Capacity (MW)	25164	31601	31601	44386	41654
Domestic Peak Demand	21379	25105	24365	35305	33601
System Peak Demand	21844	25540	24800	35305	33601
Remaining Capacity	3320	6061	6801	9081	8053
Percent of System Peak	15	24	27	26	24
Energy Production (GW.h)	120605	149752	146375	221590	213753
Hydro	40698	39904	39904	43745	43745
Coal	37320	16781	13404	54545	44230
Nuclear	40818	90601	90601	115915	122475
Other	1769	2466	2466	7385	3303
Domestic Consumption (GW.h)	118383	144459	140179	215710	205440
Net Interprov. Transfers out (in)	(8235)	(3107)	(4107)	(4307)	(4307)
Net Exports	10457	8400	10303	10187	12620

Table 4-9

Generation of Electricity in Manitoba

	1984	1990 Low Price Case	1990 High Price Case	2005 Low Price Case	2005 High Price Case
Generating Capacity (MW)	4342	4854	4854	7561	7363
Domestic Peak Demand	2829	3776	3737	5704	5508
System Peak Demand	2829	3776	3737	6754	6558
Remaining Capacity	1513	1078	1117	807	805
Percent of System Peak	53	29	30	12	12
Energy Production (GW.h)	21487	22647	22657	37611	37391
Hydro	21225	22391	22391	36881	36881
Coal	148	133	143	607	387
Nuclear	0	0	0	0	0
Other	114	123	123	123	123
Domestic Consumption (GW.h)	15242	18440	18250	27900	27180
Net Interprov. Transfers out (in)	1232	1407	1407	1607	1607
Net Exports	5013	2800	3000	8104	8604

Table 4-10

Generation of Electricity in Saskatchewan

	1984	1990 Low Price Case	1990 High Price Case	2005 Low Price Case	2005 High Price Case
Generating Capacity (MW)	2515	3237	3237	4322	4722
Domestic Peak Demand	2278	2625	2712	3850	4016
System Peak Demand	2285	2625	2712	3850	4016
Remaining Capacity	230	612	525	472	706
Percent of System Peak	10	23	19	12	18
Energy Production (GW.h)	11542	13491	13933	20090	20960
Hydro	1704	3775	3775	3815	3815
Coal	9100	9045	9406	15604	16358
Nuclear	0	0	0	0	0
Other	738	671	752	671	787
Domestic Consumption (GW.h)	11814	13691	14133	20290	21160
Net Interprov. Transfers out (in)	(292)	(300)	(300)	(300)	(300)
Net Exports	20	100	100	100	100

purchasing a little more, on average, than it sells, and its trade with the United States and Alberta is quite small. There is no reason to think that this will change. Since Saskatchewan has a substantial resource of inexpensive lignite coal, we assume that new coal units will be built as needed, similar to the recently announced Shand generating station. A first unit of 300 megawatts is scheduled for completion in 1991. Peaking needs are assumed to be met by a combination of out-of-province purchases and gas-burning combustion turbine units.

Alberta

The 1984 in-province demand for electricity was 31.2 terawatt hours. We project that this will grow to 48.4 and 57.1 terawat hours in 2005 for the low and high oil price cases respectively. The corresponding annual load growth rates are 2.1 and 2.9 percent. Relative to other provinces, Alberta's electricity demand shows the largest sensitivity of electricity demand to oil prices because of the major role the petroleum industry plays in the provincial economy.

Alberta's current generating capacity mix is about 60 percent coal, 20 percent gas, 16 percent hydro and 4 percent oil and other.

Coal resources in Alberta are plentiful and inexpensive to extract. We assume that, consistent with the province's development plans, all new large capacity additions will be coal-fired, beginning with the next major new addition in 1988 of a 400 megawatt unit called Genessee II. Peaking capacity will be supplied using gas burning combustion turbine units.

Alberta now possesses a major interconnection with B.C. Hydro. We assume that these two provincial

Table 4-11

Generation of Electricity in Alberta

	1984	1990		2005	
		Low Price Case	High Price Case	Low Price Case	High Price Case
Generating Capacity (MW)	7202	8466	8466	10365	12265
Domestic Peak Demand	5475	5970	6593	8505	10058
System Peak Demand	5475	5970	6593	8505	10058
Remaining Capacity	1727	2496	1873	1860	2207
Percent of System Peak	32	42	28	22	22
Energy Production (GW.h)	31159	34449	38131	48368	59070
Hydro	1427	1636	1636	1636	1636
Coal	25768	29329	32242	41177	51898
Nuclear	0	0	0	0	0
Other	3964	3484	4253	5555	5536
Domestic Consumption (GW.h)	31196	34050	37541	48369	57080
Net Interprov. Transfers out (in)	(35)	(401)	(410)	(1001)	(1010)
Net Exports	(2)	800	1000	1000	3000

utility systems will cooperate in reserve sharing and in making economy transactions. As well, we assume that, starting in the early 1990s, Alberta will be able to export a modest amount of interruptible energy to the United States using British Columbia's existing international interconnections.

While these export sales will be higher in our high price case, the overall levels are assumed to be quite small relative to Alberta's potential surpluses and the size of the market in the United States. At the present time, the United States northwest is well supplied with hydro energy but transmission lines from there to California are congested. In the longer term, while markets might open for coal-generated electrical energy from Alberta, competition from adjacent coal producing areas in the United States is expected to keep export levels low.

British Columbia

In British Columbia, the 1984 in-province electricity demand was 45.6 terawatt hours. We project that this will grow to 72.5 and 65.0 terawatt hours in 2005 for the low and high price cases respectively. This translates into annual growth rates of 2.2 and 1.7 percent. British Columbia's generating capacity mix is currently about 86 percent hydro, 10 percent gas and 4 percent oil and other types.

British Columbia has abundant undeveloped hydro resources and we assume, consistent with current utility plans, that future major capacity additions will all be hydro-based.

The province has interconnections with Alberta, the northwestern United States and a minor link with Alaska. Alberta and British Columbia are currently using the new interconnection between them to make modest levels of interruptible transactions, and to provide reserve. We assume that these transactions will expand moderately over the study period. We also assume that Alberta will be exporting modest amounts of coal-based electrical energy through British Columbia. British Columbia exports a substantial amount of hydro energy, most of it on an interruptible basis. We expect that these authorized levels of sales will continue as surpluses and transmission capacity permit.

In addition, we assume that the province's marketing efforts will yield major potential firm unit participation exports beginning in 1993. We anticipate that by that time, the current hydro surplus in the United States northwest will have disappeared, that new capacity will be required, and that British Columbia will be an economically attractive supply source relative to other options available to the export market. If it occurs, this export will entail the pre-building of the 900 megawatt Site C hydro plant and the sale of most of its output for the rest of the study period.

Yukon

The Yukon's electrical energy demand in 1984 was 254 gigawatt hours. We expect this to grow to 277 and 352 gigawatt hours in 2005 for the low and high price cases respectively. The projections include the increased activity arising from the reopening of the Cyprus-Anvil lead-zinc mine. The difference between the two price cases is attributable to the increased oil exploration activity likely to accompany a higher oil price assumption.

In the Yukon, about 62 percent of the generating capacity is hydroelectric and 38 percent is oil. For both price cases we assume that future capacity additions will be

Table 4-12

Generation of Electricity in British Columbia

	1984	1990		2005	
		Low Price Case	High Price Case	Low Price Case	High Price Case
Generating Capacity (MW)	12800	12854	12854	16547	15247
Domestic Peak Demand	8250	9788	9416	13101	11730
System Peak Demand	8257	9795	9423	13933	12562
Remaining Capacity	4543	3059	3431	2614	2685
Percent of System Peak	55	31	36	19	21
Energy Production (GW.h)	52378	59252	58929	78835	71470
Hydro	50232	56299	56299	74361	67462
Coal	0	0	0	0	0
Nuclear	0	0	0	0	0
Other	2146	2953	2630	4474	4008
Domestic Consumption (GW.h)	45625	54337	52314	72370	65005
Net Interprov. Transfers out (in)	31	400	410	1001	1010
Net Exports	6722	4515	6205	5464	5455

Table 4-13

Generation of Electricity in Yukon

	1984	1990		2005	
		Low Price Case	High Price Case	Low Price Case	High Price Case
Generating Capacity (MW)	122	122	122	122	122
Domestic Peak Demand	53	46	46	49	62
System Peak Demand	53	46	46	49	62
Remaining Capacity	69	76	76	73	60
Percent of System Peak	130	165	165	149	97
Energy Production (GW.h)	254	262	262	277	352
Hydro	232	223	223	237	302
Coal	0	0	0	0	0
Nuclear	0	0	0	0	0
Other	22	39	39	40	50
Domestic Consumption (GW.h)	254	262	262	277	352
Net Interprov. Transfers out (in)	0	0	0	0	0
Net Exports	0	0	0	0	0

diesel, although none will be needed for some time. Approximately 91 percent of electrical energy generation was from hydro in 1985, although this was concentrated at Whitehorse.

We assume that hydro and oil generation will continue to supply the Yukon's electrical energy needs throughout the study period.

Northwest Territories

The 1984 Northwest Territories' electricity demand was 523 gigawatt hours. We anticipate that this will grow to 838 and 803 gigawatt hours in 2005 for the low and high oil price cases respectively.

While the Northwest Territories' generating capacity is made up of about 79 percent diesel units and 21 percent hydro, electricity generation in 1984 was about 65 percent hydro, the balance coming from diesel units. The reason for this seeming imbalance is the large amount of reserve capacity that must be installed at each remote location to ensure reliable electricity supply in winter. Again, as in the Yukon, much of the hydro generation is concentrated near the capital, Yellowknife, and the rest of the territory is mainly dependent on oil. We assume that all new capacity additions will be diesel.

4.3 Implications for National Capacity and Production

The implications of the provincial analysis for the evolution of national generating capacity and electricity production are summarized for each case in Table 4-15. Because the low price case corresponds to a higher overall growth in electricity demand, there is an advancement of generating plant additions relative to the high price case of about 5 gigawatts by 2005.

Table 4-14

Generation of Electricity in Northwest Territories

	1984	1990 Low Price Case	1990 High Price Case	2005 Low Price Case	2005 High Price Case
Generating Capacity (MW)	191	191	191	229	219
Domestic Peak Demand	193	134	131	190	183
System Peak Demand	193	134	131	190	183
Remaining Capacity[a]	-2	57	60	39	36
Percent of System Peak	-1	43	46	21	20
Energy Production (GW.h)	523	571	554	838	803
Hydro	317	303	303	303	303
Coal	0	0	0	0	0
Nuclear	0	0	0	0	0
Other	206	268	251	535	500
Domestic Consumption (GW.h)	523	571	554	838	803
Net Interprov. Transfers out (in)	0	0	0	0	0
Net Exports	0	0	0	0	0

[a] The negative values are due to the peak load being the sum of all non-coincident peak loads which overstates the actual peak load.

Table 4-15

Generation of Electricity in Canada

	1984	1990 Low Price Case	1990 High Price Case	2005 Low Price Case	2005 High Price Case
Generating Capacity (MW) [a]	95497	107385	107535	150550	144950
Domestic Peak Demand[b]	72396	82376	81016	118880	114545
System Peak Demand[c]	73258	87833	86673	127772	123403
Remaining Capacity	22239	19552	20862	22778	21547
Percent of System Peak	30	22	24	18	17
Energy Production (GW.h)	425407	509439	511269	718603	707703
Hydro	283300	328047	328577	428054	417939
Coal	78808	66117	65798	141651	138841
Nuclear	49247	99519	99765	124833	131635
Other	14052	15756	17129	24065	19288
Domestic Consumption (GW.h)	386316	456482	451486	668553	652776
Net Exports	39091	52957	59783	50050	54927

[a] Generating capacity in this table includes purchased capacity.
[b] These numbers are the sum of provincial peak demands, which are not necessarily coincident peaks.To this extent, remaining capacity and percent of system peak values may be understated on a national basis.
[c] System Peak Demand total includes Domestic Peak Demand figure for Newfoundland because of a large sales component to Quebec.

In Table 4-15, "Domestic Peak Demand" and "System Peak Demand" are the sums of provincial peaks. Since the peaks in different provinces do not occur at the same time (are non-coincident) the national numbers may overstate that total peak. Thus they give only a gross indication of the level of national peak demand. As a consequence the national "Remaining Capacity" numbers may be understated.

Table 4-16 summarizes the shares of total Canadian electricity production and generating capacity by type in 1984 and projections for 1990 and 2005. It is clear that hydro is expected to provide the major share of total electricity production and capacity, although an increasing role is expected for nuclear. The detailed implications at the provincial level have been discussed above.

Capacity is expected to grow from 90 gigawatts in 1984 to about 115 gigawatts in 1995 for both cases. By 2005, total capacity is projected to increase to about 145 and 140 gigawatts for the low and high price cases respectively.

Total production was 425 terawatt hours in 1984. It is projected to grow to 719 terawatt hours and 708 terawatt hours in 2005 in the low and high cases respectively.

Hydroelectricity

In 1984, 283 terawatt hours were generated by hydro plants. By 2005 this source is anticipated to increase to 428 terawatt hours or about 60 percent of total electricity produced for the low price case. In the high price case, hydro is expected to increase to 418 terawatt hours in 2005, also about 60 percent of the total electricity produced. Even at

Table 4-16

Electricity Production and Generating Capacity by Fuel Type

Electricity Production, Terawatt hours (TW.h)

	1984		1990				2005			
			Low Price Case		High Price Case		Low Price Case		High Price Case	
	TW.h	Percent	TW.h	Percent	TW.h	Percent	TW.h	Percent	TW.h	Percent
Coal	78.8	19	66.1	13	65.7	13	141.7	20	138.8	20
Hydro	283.3	66	328.0	64	328.6	64	428.0	60	417.9	59
Nuclear	49.2	12	99.5	20	99.8	20	124.8	17	131.6	19
Oil and Nat. Gas	11.8	3	12.8	3	14.2	3	19.4	3	14.6	2
Other	2.3	0	3.0	1	2.9	1	4.7	1	4.7	1
Total Canada	425.4	100	509.4	100	511.2	100	718.6	100	707.6	100

Generating Capacity, Gigawatts (GW)

	1984		1990				2005			
			Low Price Case		High Price Case		Low Price Case		High Price Case	
	GW	Percent	GW	Percent	GW	Percent	GW	Percent	GW	Percent
Coal	16.1	18	19.1	19	19.1	19	28.7	20	29.2	21
Hydro	55.0	60	58.4	57	58.4	57	81.5	56	77.2	55
Nuclear	7.7	8	13.5	13	13.5	13	18.7	13	18.7	13
Oil and Nat. Gas	9.3	11	8.5	9	8.7	9	13.5	9	11.7	9
Other	2.3	3	2.5	2	2.5	2	2.7	2	2.7	2
Total Canada	90.4	100	102.0	100	102.2	100	145.1	100	139.5	100

Note: The numbers in this table have been rounded.

Source: Appendix Tables A4-4 and A4-5

that date, several provinces will have significant, undeveloped hydro sites.

Coal

In 1984, 79 terawatt hours of electricity were generated from coal. This was about 19 percent of the electricity produced in Canada. In order to generate this electricity 854 petajoules of coal were consumed.

We project that the amount of coal-generated electricity will decrease in the short term to 1990 and then will increase to 142 and 140 terawatt hours by the year 2005, for the low and high price cases respectively. For both cases this represents about 20 percent of the total electricity expected to be produced in 2005, a substantial increase from an estimated 13 percent in 1990. To generate this electricity about 1600 petajoules of coal would be required. Ample supplies of coal will be available to satisfy the needs for thermal generation throughout the study period.

Uranium

The amount of electricity generated at nuclear plants was 49 terawatt hours in 1984, almost 12 percent of the total electricity produced. The amount of uranium used to produce this electricity was 596 petajoules.

We expect nuclear-generated electricity to grow to 125 and 132 terawatt hours in the year 2005 for the low and high price cases respectively. For both cases, this represents about 18 percent of the total electricity expected to be generated in 2005. It would require about 1500 petajoules and 1600 petajoules of uranium for the low and high price cases respectively, to generate this electricity. Ample supplies of uranium will be available throughout the review period.

Oil

In 1984, there were about 6 terawatt hours generated from oil, about 2 percent of the total. The total amount of oil used to generate this electricity was 66 petajoules.

We are projecting that the amount of oil-generated electricity will increase to about 11 terawatt hours and 6 terawatt hours by 2005 for the low and high price cases respectively. For both cases this corresponds to about 1 percent of the total electricity expected to be generated in 2005. This would require 116 petajoules and 65 petajoules of oil for the low and high price cases respectively. One of the continuing uses of oil will be to generate electricity from internal combustion plants in isolated locations.

Natural Gas

In 1984, 6 terawatts hours of electricity were generated from natural gas, about 1 percent of the electricity produced. This required 49 petajoules of natural gas.

We anticipate that for both price cases, natural gas will still account in 2005 for about 1 percent of total electricity production. It would require about 70 petajoules of natural gas for electricity generation in both price cases.

Other

Electricity generated by other fuels amounts to less than 1 percent of total annual generation throughout the period under review. This category includes hog fuel, pulping liquor, coke oven and blast furnace gas, other biomass and fossil fuel by-product sources, and wind and solar power. While these resources will grow in use over the study period, their overall contribution to energy generation will remain small. This is not to say that in certain regions of the country, these resources, particularly wind, small hydro and solar power, may not be important.

4.4 Exports

We are projecting that total exports of electricity will increase from 41 terawatt hours in 1984 to about 55 terawatt hours in 2000 and remain at about that level thereafter.

In 1984 about 10 terawatt hours (or about 23 percent of total exports) were some type of firm sale. By 2005, we project that firm exports will increase to about 25 terawatt hours or about 46 percent of the total, reflecting the new marketing strategy of a number of utilities, discussed above.

This results from the inclusion in our projections of an estimate of potential exports resulting from the advancement of generating capacity to serve U.S. markets. It is important to note that these estimates of potential firm exports are intended only as an illustration of the order of magnitude of the exports which might occur as a result of this activity.

Exports of interruptible electricity which were about 30 terawatt hours in 1984, are expected to be about 25 terawatt hours in 2005 or about 4 percent of total electricity production. This decline in the relative importance of interruptible energy results from the methodology of our study, which by its nature does not project large on-going differences between capacity and requirements.

While the pattern of exports is quite similar for both oil price cases, we assume that there will be some increase in overall exports in the high price case. This results because of reduced provincial demand, particularly in British Columbia, Ontario and Quebec, thus providing larger surpluses over the next decade, and a better opportunity for exporting surplus energy, primarily on an economy basis, when fossil fuel prices are higher.

While large transfers of electricity are made between several provinces, in many cases the United States provides a larger and often more accessible market for Canadian utilities. This situation is expected to continue over the study period. An estimate of the net interprovincial transfers is provided in Appendix Table A4-5.

The outlooks for total electricity exports by province for selected years are contained in Table 4-17. In the remaining years of this decade the major exporters are expected to be Quebec, Ontario, British Columbia, Manitoba and New Brunswick. Exports from Alberta through British Columbia are expected to start in 1991.

Electricity exports are expected to continue to be produced largely by hydro and coal resources (Figure 4-1), with coal increasing in importance over the review period, and hydro decreasing. Exports of electricity generated from coal increase more rapidly in the high price case than in the low because of their greater comparative advantage in market areas where oil-fired generation is predominant.

In 1984 about 10 percent of Canada's total electricity production was

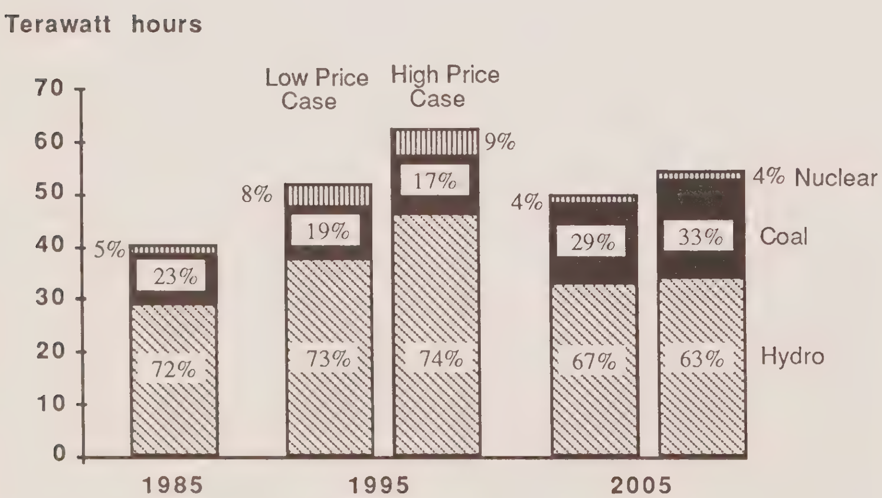
Table 4-17
Forecast of Net Electricity Exports
(Terawatt hours)

	1984	1990		2005	
		Low Price Case	High Price Case	Low Price Case	High Price Case
New Brunswick	5.6	7.3	7.6	8.5	8.2
Quebec	11.2	29.1	31.6	16.7	17.0
Ontario	10.5	8.4	10.3	10.2	12.6
Manitoba	5.0	2.8	3.0	8.1	8.6
Saskatchewan	0.0	0.1	0.1	0.1	0.1
Alberta	0.0	0.8	1.0	1.0	3.0
British Columbia	6.7	4.5	6.2	5.5	5.5
Total Canada	39.0	53.0	59.8	50.1	55.0

Note: The numbers in this table have been rounded.

Source: Appendix Table A4-7

Figure 4-1
Net Electricity Exports by Fuel Type



Source: Appendix Table A4-8

exported. Our projections imply a decline in this proportion to about 7 percent by 2005. This drop reflects the disappearance of the surplus "bubble" which currently exists and the marketing strategy described above. While we are assuming a moderate level of exports, if other export possibilities still in the preliminary discussion stages come to pass, exports could be substantially larger.

Summary

There are no inherent constraints on the ability of utilities to provide Canadians with reliable supplies of electricity over the study period. Given the abundance of basic energy resources, the diversity of available production technologies and appropriate planning, even higher rates of growth than we project could be accommodated.

For Canada as a whole, we expect that the demand for electricity will grow at 2.8 and 2.6 percent annually over the review period for the low and high price cases respectively. These rates of growth are remarkably similar, given the different circumstances which define the two cases. This is because as oil prices rise two counterbalancing things happen. One is that economic activity declines, in turn reducing total energy demand, including the demand for electricity. However, the second is that the higher oil prices lead to electricity capturing a larger share of the energy market. Put more simply, as oil prices rise, electricity captures an increasing share of a declining market.

With respect to electricity exports, our assumptions reflect the current trends in which several provinces are becoming increasingly aggressive in pursuing export opportunities. This approach to electricity production planning and marketing is expected to result in robust export activity through the study period.

Chapter 5
Natural Gas

This chapter contains a discussion of the supply of Canadian natural gas from both conventional and frontier sources.

We begin by assessing established reserves, reserves additions and ultimate potential in the conventional producing areas, and then examine current reserves in the frontier areas and our productive capacity projections for both conventional and frontier areas. We then discuss the prospects for exports and conclude with an assessment of the implications for supply/demand balances for the conventional areas alone, and with frontier supply added.

More than 99 percent of Canada's current natural gas supply comes from the Western Canada Sedimentary Basin, which includes parts of the provinces of Alberta, Saskatchewan, British Columbia and the southern Yukon and Northwest Territories. The remainder comes from sources in eastern Canada.

When the supply of natural gas from the Western Canada Sedimentary Basin declines, there will be a progressively greater dependency on alternatives, such as gas from the Mackenzie Delta, the Arctic Islands and offshore regions, where substantial quantities have already been discovered. The availability of future supplies will depend critically upon exploration success, price expectations, development and operating and transportation costs, prevailing fiscal regimes, development of new technologies and industry investment strategies.

5.1 Established Reserves

We estimate Canada's remaining established reserves of marketable natural gas as of 31 December 1984 to be 96.2 exajoules. Of this total, 78.6 exajoules are in the conventional producing areas and 17.6 exajoules in the Mackenzie Delta and the Arctic Islands. A regional breakdown is shown in Table 5-1.

In 1984 3.5 exajoules of new gas were added to reserves in the conventional areas through new discoveries and appreciation of existing reserves. However, downward revisions of 2.0 exajoules and production of 3.0 exajoules during the year resulted in a net decrease in remaining reserves from year-end 1983 of 1.5 exajoules. The downward revisions, for the most part in Alberta, reflect pool re-evaluations based mainly on production decline rate analysis.

Our preliminary estimate for the conventional areas for year-end 1985 of 76.7 exajoules represents a further decrease in remaining established reserves of some 1.9 exajoules. This decrease results from production of 3.2 exajoules and gross additions of approximately 1.3 exajoules. This is the third consecutive year that remaining reserves in the conventional areas have declined. Figure 5-1 shows the

Table 5-1

Remaining Established Reserves of Marketable Natural Gas at 31 December 1984

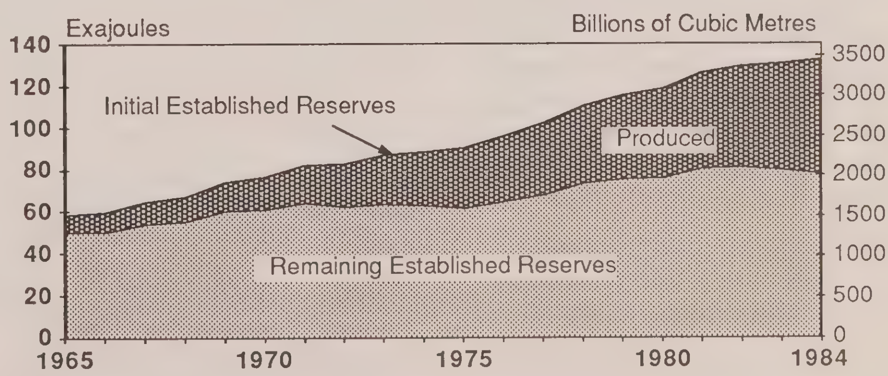
(Exajoules)

British Columbia	9.3
Alberta	66.5
Saskatchewan	1.9
Southern Yukon and NWT	0.4
Ontario and Other Eastern Producing Areas	0.5
Total Conventional Areas	**78.6**
Mackenzie Delta	5.6
Arctic Islands	12.0
Total Canada	**96.2**

Note: The numbers in this table have been rounded.

Figure 5-1

Established Reserves of Marketable Natural Gas Conventional Areas



Source: Appendix Table A5-1

changes in both the initial (before production) and remaining established reserves of marketable natural gas during the past 20 years.

Alberta accounts for about 85 percent of the remaining reserves in the conventional areas. More than 60 percent of Alberta's reserves are contained in approximately 1100 larger pools, the initial reserves of which average some 80 petajoules each. Most of these have been producing for some time. In contrast, the other 40 percent, some 24 exajoules, is in small pools assigned reserves of 10 petajoules or less, and with an average reserve of less than 2 petajoules. There are approximately 16 500 such small pools, mostly single wells, which for the most part have never been placed on production. Recent studies we have carried out relating the production history of small producing pools to their assigned reserves, indicate that the reserves assigned to the yet unproduced small pools may be overestimated.

We have attempted to determine the effect of price variations on remaining established reserves. To do so we conducted an analysis of the economic viability of bringing onstream Alberta's unconnected gas pools. The study indicates that, in our low price case, some 4 exajoules of the approximately 20 exajoules currently unconnected will probably be beyond economic reach throughout the projection period. In the high price case some 2 exajoules may not be economically connectable during the period.

5.2 Reserves Additions and Ultimate Potential–Conventional Areas

In order to verify that development of the reserves underpinning our supply projections are economically viable, and to provide a basis for estimating when the development of new resources is likely to be undertaken, we compare project supply costs to the price profiles contained in our high and low cases. This comparison is conducted on the basis of so-called social supply costs.

Social supply costs are values per unit of output, which, when earned on all units of production over the life of the project, will yield a 10 percent real rate of return (the social discount rate[1]) on all related future exploration and development expenditures. This return is gross of taxes and royalties and implicitly incorporates a risk premium that reflects only the average level of risk associated with all capital investments in Canada. These social supply costs represent the minimum values which must be placed on each unit of production to cover the direct capital, labour and other costs required to develop the resource.

An important feature of social supply costs is that they are independent of both the fiscal regime and the particular tax and financial status of the corporate entity which may ultimately harvest the resource. Therefore, social supply costs are particularly useful in developing a supply outlook over a time period characterized by fiscal provisions which vary between firms and which will undoubtedly change over time. The unit social supply costs estimated in this report would reflect the product price which would enable the project to be developed, provided that the 10 percent rate of return reflected by the social discount rate were sufficient to meet the taxation, rate of return and royalty expectations of governments, investors and resource owners respectively.

Industry, of course, does not invest on the basis of social rates of return, but rather on an assessment of private rates of return which account for risk premiums and how applicable taxes and royalties affect the firm involved. However, because of the wide variation in the tax and royalty positions of companies and their individual assessment of risk and the uncertainties about future fiscal systems, private costs and returns across the industry are virtually impossible to estimate. Accordingly, we accept the social supply cost and its implicit rate of return as a proxy for the private, recognizing that in many cases it will understate the total costs which will be incurred by the private sector. We recognize that taxation can generate differences between private and social profitability, but in the long run it is reasonable to expect that the fiscal regime will be such as to allow socially feasible projects to occur.

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1. There has been much research and discussion about the value of the real social discount rate for Canada. The Federal Treasury Board recommends a rate of 10 percent. Board staff have reviewed existing work, undertaken consultations and recommended that the social discount rate be 8 percent, with values of 6 percent and 10 percent for testing the sensitivity of "net benefit" estimates to variation in the social discount rate.

   Board staff have used 8 percent to determine the net benefits to Canada from licensing certain energy exports. In this report we use 10 percent - the upper end of the recommended range - to provide a more stringent test of what resource developments may be economically feasible with the energy prices and project development costs assumed here. This additional stringency reduces the risk of over-estimating the amount of additional energy supply expected as a result of new project developments - especially the very capital-intensive ones.

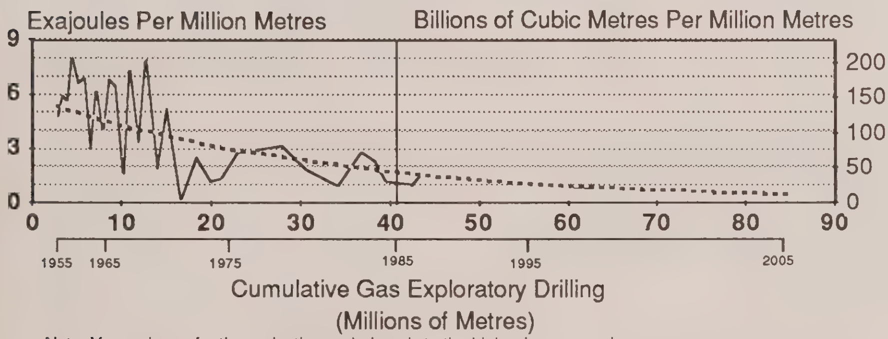
Table 5-2

Estimated Social Supply Costs and Prices of Natural Gas at the Field Gate[a] Western Canada

	1986	1987	1995	2005
		($C 1986 per Gigajoule)		
Natural Gas Prices				
Low Price Case	2.10	0.86	1.55	1.50
High Price Case	2.10	1.43	3.30	3.25
Social Supply Costs [b]				
For New Discoveries	2.50-3.10	2.50-3.10	2.65-3.30	2.80-3.50
For Additions	1.55-1.95	1.55-1.95	1.70-2.10	1.95-2.55

[a] Field gate prices are the prices at the Alberta border (Table 2-3), less the cost of transportation to the Alberta border from the field.
[b] The ranges reflect variations in prospect quality.

Figure 5-2
Relationship of Natural Gas Reserves Additions Rate to Cumulative Gas Exploratory Drilling Conventional Areas



Note: Years shown for the projection period apply to the high price case only.
Source: Appendix Table A5-2

Table 5-2 compares the estimated ranges of social supply costs of western Canada natural gas with both the high and low field gate price projections. Two different supply cost estimates are shown. The higher estimates represent only the costs of new discoveries projected to be made during the review period; the lower estimates consider appreciation of past discoveries as well. We have shown both estimates, since exploring for gas in the past has resulted in upward revisions to reserves assigned to earlier discoveries.

We expect reserves additions per metre of exploratory drilling to continue to decrease as prospects for new discoveries diminish; as a result social supply costs increase over time. This accounts for the higher costs in later years shown in the table. We have indicated a likely range for the average cost of reserves additions to account for the expected variation in prospect quality.

In the high price case, projected field gate natural gas prices exceed estimated average social supply costs so that exploration for gas appears profitable. In the low price case, exploration for gas does not appear profitable on average. However, lower cost projects yielding higher rates of return will be developed and natural gas will be found incidental to the search for oil. In examining these price/cost relationships, it is important to bear in mind that (as noted in Chapter 2) our natural gas pricing framework results in a gas price projection which is lower than would occur with price differentiation.

There will always be uncertainty associated with projections of reserves additions, based as they are on perceptions of future drilling activity and success rates, economic conditions including market opportunities and ultimate potential. Compounding these uncertainties today are the lower world oil prices and their effects on the oil and gas industry, and the uncertainty of the impact on the industry of a market sensitive pricing regime for natural gas.

Our reserves additions projections are based on an extrapolation of the historical relationship between the rate of reserves additions and the amount of exploratory drilling.

Figure 5-2 illustrates the decline in reserves additions per unit of exploratory drilling in western Canada. The amount of gas discovered by a given amount of drilling declines over time, as prospects become fewer and harder to find.

We developed projections of future exploratory drilling in total for each price case, using estimates of production levels, cash flow and producer profitability, and their interrelationship.

It is not possible for us to determine if an individual well was drilled with the intent of finding oil or of finding gas. Accordingly for historical data we use the drilling results to make the division. Wells which discovered oil are classed as oil directed, whereas those which found gas are classed as gas directed. The abandoned wells in each year are assigned to one of these two categories in the same ratio as the successful wells. Based on this review of the historical relationship between gas and oil directed drilling, and our perception of future market opportunities and exploration prospects for hydrocarbons in the Western Canada Sedimentary Basin, we judgementally divided the total future drilling projections into gas directed and oil directed components as shown in Figure 5-3.

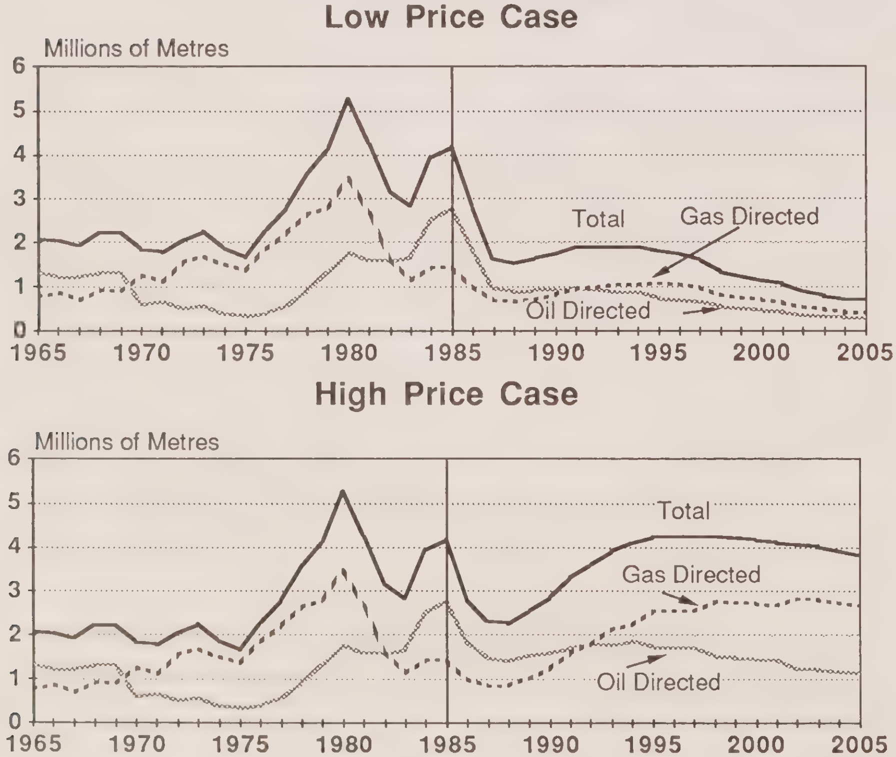
We assume that during the remainder of the 1980s, in view of depressed gas export markets and the quantity of unconnected gas reserves in inventory, a somewhat greater proportion of exploratory effort will be oil directed as has been the case in the recent past. Beginning in the early 1990s however, the excess gas deliverability in the U.S. is assumed to decline (Section 5.5), creating a greater incentive for increased gas exploration in Canada to meet potentially higher export levels.

The gas directed drilling projections in Figure 5-3 are combined with our projection of the reserves additions rate (Figure 5-2) to develop the high and low price case reserves additions projections shown in Figure 5-4[1]. The influence of the decline in rate of additions per unit of drilling is particularly evident in the high price case. In that case we project drilling levels to be close to the high levels which occurred in the late 1970s. Notwithstanding the similarity of drilling levels, annual reserves additions are projected to be much lower in the future than in the past. In order to attain the drilling activity in our low price case projection, we have assumed some cost reduction and rationalization of the industry. In fact, the supply economics associated with this price case suggests that it is probably unsustainable.

In the high price case, a total of 37 exajoules is projected to be added during the study period. This compares to some 40 exajoules of additions projected to be added during the same period of time in the reference case of the September 1984 Report.

In the current high price case drilling activity and reserves additions are projected to decline until 1988 and

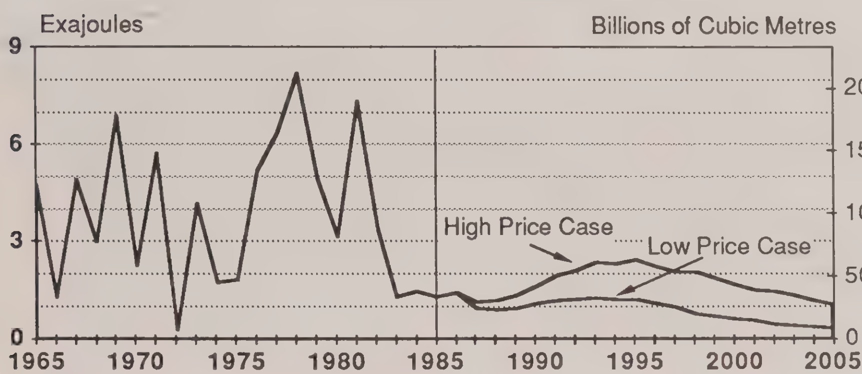
Figure 5-3
Division of Exploratory Drilling Conventional Areas



Source: Appendix Tables A5-2 and A6-4

1. The abnormally high reserves additions shown for 1976 and the several years following appear to have resulted from a combination of escalating drilling levels and the availability of an inventory of drilling prospects which had been uneconomic at prices in effect earlier.

Figure 5-4
Marketable Natural Gas Reserves Additions Conventional Area



Source: Appendix Tables A5-1 and A5-2

then increase gradually until 1995. The increase reflects the anticipated dissipation of the U.S. gas deliverability surplus through the late 1980s and early 1990s, and the associated increase in market opportunities for Canadian gas. After 1995 the profile of additions gradually decreases, reflecting the diminishing prospects for new discoveries within the Western Canada Sedimentary Basin, which results in a decline in both the additions rate and gas directed exploration.

In the low price case, where only 20 exajoules are added during the projection period, the additions follow a similar, though more subdued profile, reflecting the reduced economic incentive to explore for gas and the consistently lower level of drilling activity.

We estimate an ultimate potential for the Western Canada Sedimentary Basin of between 170 and 200 exajoules, unchanged from the September 1984 Report. Of the potential, 133 exajoules had been discovered by the end of 1984. For our reserves additions projections (Figure 5-4) we use the mean value, 185 exajoules, as a constraint on the quantity of new gas that could be added to reserves during the projection period. A larger quantity of gas would be added if the ultimate potential is higher than we currently estimate it to be. Moreover, higher prices would in all likelihood result in higher levels of drilling which would in turn result in increased reserves additions during the projection period.

5.3 Frontier Areas

The Canadian frontier regions have significant geological potential and could account for a substantial portion of future natural gas supplies. The quantities that will be exploited commercially and the timing of production, will however depend upon many factors, including the total amount discovered, prevailing economic conditions and technological progress. Uncertainties about the development, production and transportation of natural gas from the frontier areas make projecting supply from this source extremely difficult. Furthermore, the current low world oil prices and the phasing out of the Petroleum Incentives Program have resulted in cutbacks in exploration activity, adding to the uncertainties of assessing the outlook for frontier supply.

Major natural gas reserves potential is recognized in three frontier areas currently being explored: the Mackenzie Delta/Beaufort Sea, the Arctic Islands and the east coast offshore. To date there has been no production of natural gas from any of these areas.

The Board previously determined that there were established natural gas reserves of some 6 exajoules and 12 exajoules in the Mackenzie Delta/Beaufort Sea region and the Arctic Islands respectively. We still consider these estimates valid, even though additional quantities of northern gas have since been found, notably in the Beaufort Sea. We do not at present consider these as established reserves since their economic viability remains uncertain and since the estimates have not been publicly tested by the Board through the hearing process. In addition, we do not have access to all the confidential data required for independent assessments on a pool by pool basis. For the same reasons no established gas reserves have yet been recognized by the Board for the east coast offshore region although several discoveries have been made.

The Canada Oil and Gas Lands Administration (COGLA) provided estimates in its 1985 Annual Report of potentially recoverable resources discovered to date on Canada Lands. These estimates of "discovered resources", for gas, are shown in Table 5-3. There are no economic constraints imposed on these estimates, so they cannot be compared directly with the Board's estimates of established reserves.

Table 5-3

COGLA Estimates of Discovered Resources of Natural Gas Frontier Regions

	(Exajoules)
Mackenzie Delta/Beaufort Sea	10.6
Arctic Islands	15.5
East Coast Offshore	10.4

Notes :
The numbers in this table have been rounded.

Discovered resources are estimates of the quantities of crude oil or natural gas potentially recoverable from known reservoirs, but of uncertain economic viability.

5.4. Productive Capacity

The productive capacity of western Canadian natural gas which we are projecting for the two price cases is illustrated in Figure 5-5 and is detailed in Appendix Tables A5-5 and A5-6.

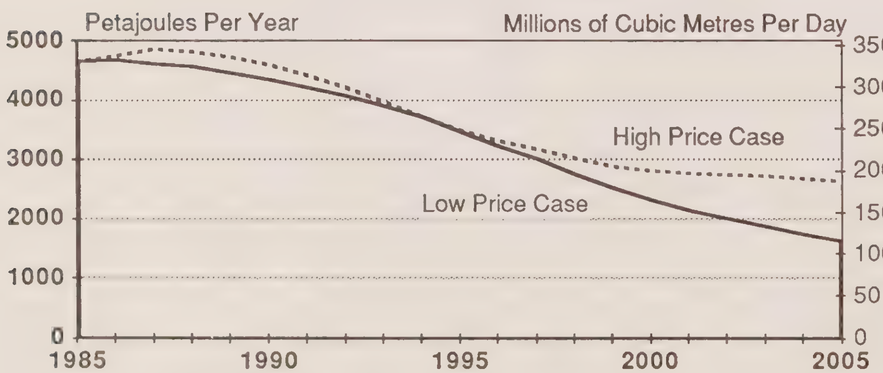
Our projection of productive capacity in the conventional areas is comprised of three components. These are productive capacity from:

- currently established reserves under contract,
- currently established reserves not as yet contracted, and
- reserves additions.

The projections of productive capacity from currently contracted reserves in Alberta for the two price cases are based on the projections in the September 1984 Report, with adjustments for actual production in 1983 and 1984 and for the effect of price on productive capacity. Our productive capacity estimates for British Columbia reflect our studies of the Westcoast supply system updated to year end 1984.

Productive capacity from over 90 percent of the reserves under contract in western Canada is derived on a pool by pool basis using our gas deliverability computer model. The model projections reflect each gas pool's well flow characteristics, basic reservoir parameters and daily contract rate. It also incorporates drilling and compression cost data and projected producer netbacks to assess the time period over which productive capacity can be maintained at or near the contract rate by adding infill wells and/or field compression.

Figure 5-5
Productive Capacity of Natural Gas Conventional Areas



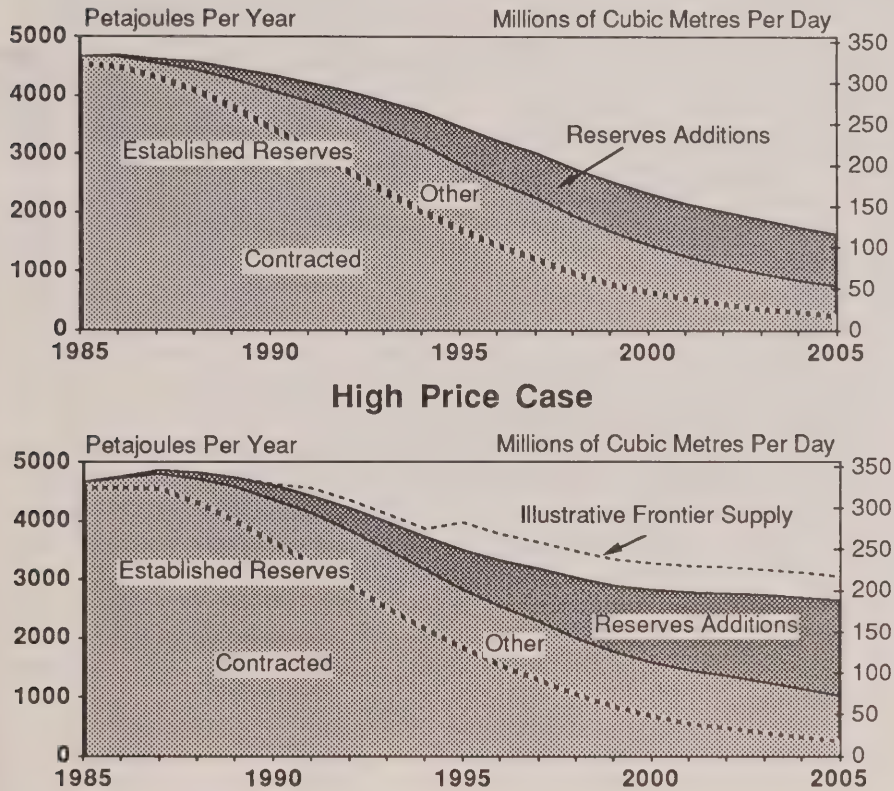
Source: Appendix Table A5-6

The forecast of productive capacity from the remaining 10 percent of contracted reserves which includes Saskatchewan reserves is based on either past production history or estimates published by provincial agencies or utility companies.

In order to derive our low and high price case projections of productive capacity from established reserves currently under contract, we conducted price sensitivity tests on a sample of some 100 non-associated producing gas pools in Alberta with initial reserves greater than 1500 million cubic metres. These pools represent some 20 percent of the total remaining reserves under contract. These tests suggest that productive capacity from Alberta reserves under contract would be some 5.5 percent higher in total over the projection period in the high price case than in the low price case. More than twice the amount of investment for additional wells and compression would likely occur under the high price case than in the low price case. This additional development, however, is not sufficient to prevent the inevitable decline of productive capacity from these reserves.

Figure 5-6 illustrates that productive capacity from the approximately 50 exajoules of reserves already found in the conventional areas and now under contract, will decline throughout the forecast period as a result of reservoir depletion. Productive capacity of reserves now under contract is expected to decline from a level of 4580 petajoules per year in 1985 to 278 petajoules per year in 2005 in the low price case and to 285 petajoules per year in 2005 in the high price case.

Figure 5-6
Productive Capacity of Natural Gas by Supply Source
Low Price Case



Source: Appendix Table A5-6

Productive capacity from established reserves not currently under contract and from reserves additions is projected to approximate that from reserves currently under contract in the later 1990s, and to exceed it toward the end of the projection period. The variability of these two supply components with respect to connection rates and production profiles enables them to reflect future demand and prices.

For reserves not currently under contract in Alberta and Saskatchewan, and all reserves additions, we estimate productive capacity in aggregate rather than pool by pool. As a consequence, assumptions with regard to connection schedules and deliverability profiles require careful consideration. For all existing gas pools in British Columbia, productive capacity is derived using our gas deliverability model on a pool by pool basis so that onstream dates for pools not currently under contract were required. These dates were based on information submitted by Westcoast in support of its 1985-86 tolls application and were assigned to each pool considering expected demand levels, pool size and distance from existing pipelines.

In the past we have not specifically addressed the problem of relating connection schedules for uncontracted reserves and reserves additions to a specific price scenario. There is, however, considerable room for varying connection rates; we have been told by industry representatives that given the appropriate price most new gas could be connected and producing within four years of discovery.

Productive capacity profiles for new gas can also vary. In the past we have assumed, based on consultations with industry, that gas would continue to be contracted and produced under long term contracts, hence our use of a production profile of one unit of production for each 7000 units of reserves (1:7000) for 8 years followed by an 8.22 percent per year decline. Our latest productive capacity studies suggest that the flat life period for an initial 1:7000 rate of take could be extended beyond the 8 years, but would be followed by a sharper decline. As well, production rates as high as 1:3500 with level initial production periods close to 6 years may be possible given high enough prices to support the additional development required.

In order to determine appropriate productive capacity profiles for uncontracted Alberta reserves and all reserves additions, we used our new integrated gas supply database for Alberta (which contains all the relevant reserves and deliverability data needed to estimate productive capacity) to investigate the physical and economic ability of small Alberta gas pools to produce at each of two initial rates: 1:7000 and 1:3500. Our test sample included all non-producing, non-associated gas pools with initial reserves between 150 million cubic metres and

300 million cubic metres. These pools represent some 2.5 exajoules of Alberta's 13.6 exajoules of uncontracted gas reserves excluding the low permeability shallow gas in southeast Alberta. Our analysis indicates that for both price cases productive capacity from these small pools could approximate the rate of 1:7000 for 15 or more years or the rate of 1:3500 for some 6 years.

For the high price case, we assume that uncontracted Alberta reserves and all reserves additions would continue to be contracted under long term contracts, i.e. with initial rates of 1:7000. For the low price case, we assumed that half of these reserves would be contracted at the higher initial rate of 1:3500, because of the increased need for productive capacity and the probable desire on the part of producers to recover investment as quickly as possible. We therefore used the average of the two profiles derived from our test sample.

In selecting connection rates and production profiles for the low and high price cases, we have considered the availability of reserves and the total demand for gas during the projection period. The schedules were selected such that there would be some spare capacity developed in each price case. In anticipation of increased opportunities to export natural gas, we expect that producers will develop more productive capacity in relation to the sum of domestic demand and licensed exports in the high price case than in the low price case. The connection schedules for the two price cases show some 15 percent and 30 percent excess capacities for the low and high price cases respectively. These connection schedules are shown in Appendix Table A5-4.

Using these connection schedules and production profiles results in total productive capacity projections for the two price cases that differ by 240 petajoules a year (5 percent) in 1990 and by 1010 exajoules a year (61 percent) by 2005.

The range of productive capacity projections represented by these cases does not represent a maximum range of supply availability, but rather the expected range of productive capacity given the variance in reserves additions we project and giving consideration to the expected demand over the review period. In total over the study period, productive capacity is lower than the reference case projection in the September 1984 Report by some 15 percent and 7 percent for the low and high price cases respectively.

It is possible to increase the projection of productive capacity by assuming higher initial rates of take and faster connection schedules. However, most of these adjustments have already been built into the low price projection, so that the ability to increase productive capacity in that case is probably small. On the other hand, higher initial rates of take could be introduced to the high price case resulting in a somewhat higher productive capacity in earlier years followed by a more rapid decline.

We emphasize that our supply projections reflect the natural gas price tracks we assumed. At prices above our high price case projection, increased levels of supply could occur. With higher prices, poorer quality reserves, uneconomic at lower prices, could become profitable and improved cash flow to the producing industry would support increased exploratory and development activity. Moreover, if gas prices were to follow a price differentiation scenario producer cash flow would be increased, generating higher levels of supply in both price cases than shown in our projections.

With regard to frontier supply, both the Polar and Venture projects have facility applications before the Board. These applications are incomplete; neither contains the supply information required for evaluation. Because of the uncertainty of the size of the reserves available to support these projects, we do not include supply from them in our projections. However, for illustrative purposes, we show in Appendix Table A5-6 and on Figure 5-6 (on the high price case diagram) productive capacity estimates for these projects at the levels proposed by the applicants. For Hibernia we assume that solution gas will initially be reinjected and will not therefore contribute to the total supply projected.

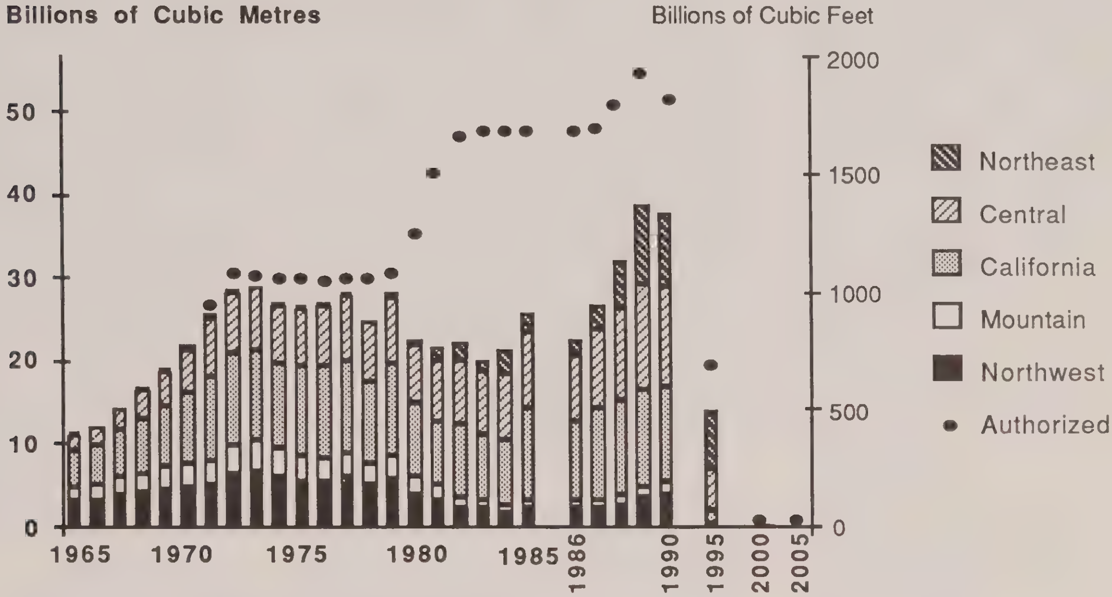
5.5 Exports

Canada has been exporting significant quantities of natural gas to the United States since the 1950s. Since the early 1970s exports have been running at annual levels of about 24 billion cubic metres (847 Bcf) and until 1980 were close to levels authorized by the Board. Large new volumes were authorized by the NEB in the early 1980s but for various reasons volumes flowing have not increased (Figure 5-7). Volumes presently authorized under licence are now close to peak levels; they will decline rapidly beginning in 1990.

Future authorizations depend on the prospects for American gas markets and on Board decisions. The focus of the analysis in this report is on the prospects for exports under existing

Figure 5-7

Natural Gas Exports Under NEB Licence



Note: Data on authorized volumes begins in 1971.
Source: Appendix Table A5-7

authorizations. This means, of course, that after 1990 our projection of exports declines rapidly, with exports virtually ceasing by the mid-1990s.

Many analysts of the American gas market, however, project a tightening of that market in years to come. The consensus is that American import requirements will rise, so the potential for further exports exists throughout the study period.

Canadian exports will be strongly influenced in the immediate future by the way in which the nature of the contractual arrangements respond to changes in the structure of American markets. They will also be affected by the nature and pace of change in the American regulatory environment. Issues related to these factors are first discussed followed by an assessment of the prospects for American supply and demand for gas and the implications for Canadian exports. The section concludes with an outlook for exports beyond the current term of authorization.

5.5.1 Structure of the Natural Gas Export Trade

Prior to 1975, export arrangements were determined by negotiation between buying and selling companies, subject to government approval. Between 1975 and 1984, export prices were set by government. In November 1984, prices were again allowed to be set between buyers and sellers, subject to a floor price equal to the Toronto city gate wholesale price. In November 1985, the Toronto floor price was replaced by a set of regional reference prices based on regulated domestic prices. Under the Natural Gas Agreement of 31 October 1985, regulated domestic prices will be replaced after 1 November 1986 by a market-oriented pricing regime which should result in more competitive regional reference prices for exports.

Export arrangements typically are between Canadian transmission companies and U.S. interstate pipelines which purchase gas under long-term contracts for resale to distribution utilities along their systems. Notable exceptions to this general rule are long-term, direct sales (sales between producers and

either distribution utilities or end users with the pipeline acting only as a transporter) by Alberta & Southern Gas Company Limited (A&S) and Pan-Alberta Gas Limited (Pan-Alberta) to California utilities (Pacific Gas and Electric, and Southern California Gas Company), and TransCanada PipeLines Limited's (TransCanada) sale to Boundary Gas Incorporated (a group of northeastern U.S. utilities).

In the past year, there has been a rapid growth in short-term, direct sales in the American market. In response to this, Canadian exporters are increasingly turning to the direct sale type of export arrangement with shorter contract periods. Both Westcoast Transmission Company Limited (Westcoast) and TransCanada have concluded direct sale agreements with U.S. utilities and/or brokers, and other exporters are in the process of negotiating additional sales of a similar nature. A&S, Pan-Alberta and Westcoast are active in the California spot market. As well, individual Canadian producers who had not been directly involved in the export market prior to 1985, are now making direct sales to U.S. utilities, brokers and end users through the vehicle of short-term (up to two years) export orders.

This trend toward direct sales in Canada's gas export trade is expected to grow, particularly in 1987 when the majority of U.S. interstate pipelines are expected to become open access transporters of gas under FERC Order 436, discussed more fully below.

5.5.2 *United States Regulatory Environment*

The prevailing American regulatory environment is a key factor affecting the demand and supply for natural gas in the U.S. and the ability of imported gas to compete in that market. This is particularly important at the present time as the U.S. gas industry moves toward deregulation during a period of intense competition from alternative energy forms and of surplus availability of natural gas.

During this transition, it is apparent that the American regulatory environment will impose greater risks on U.S. producers and Canadian exporters, while at the same time providing suppliers of gas and their purchasers with a multitude of alternatives to the traditional long-term contract supply service. It is recognized that in this new environment, Canadian exporters must be able to respond quickly to changing market conditions by providing an array of competitively priced sales services, both long- and short-term. This will be greatly facilitated when the move to market-sensitive pricing in Canada has been completed.

As noted, the U.S. industry has already responded to this freer marketplace by shifting towards a short-term marketing and transportation strategy. Creation of this short-term market has led to cost savings for consumers and encouraged long-term suppliers to offer contracts that are more market responsive.

The shift in marketing strategy in the U.S. has resulted in part from, and will be furthered by, recent U.S. regulatory initiatives, the impact of which will continue to be felt in the marketplace and by Canadian exporters for years to come.

Under the provisions of the U.S. Natural Gas Policy Act of 1978 (NGPA) approximately sixty percent of U.S. natural gas production (so-called "new" gas) was released from wellhead price control in January 1985. In 1984, the U.S. Federal Energy Regulatory Commission (FERC) issued Order 380 and in 1985 Orders 436 and 451, all of which will have a profound impact on the transportation and marketing of gas, including gas imported from Canada.

FERC Order 380, as amended, prohibits pipelines from using so-called "minimum bill" provisions in sales contracts to recover variable costs, such as purchased gas costs, that are not actually incurred. This effectively prevents pipelines from passing on to their customers take-or-pay charges (except carrying charges) incurred in their supply contracts. (Take-or-pay charges are an obligation to pay for a specified quantity of gas regardless of whether the gas is taken). This in turn increases the investor risk associated with financing of new gas supply projects, including future projects to supply Canadian gas.

FERC Order 436, as amended, is designed to increase competition in the U.S. gas industry by encouraging interstate pipelines to move toward "open access" gas transportation on their systems and away from the traditional role of providing a bundled service incorporating gas purchasing, transportation and marketing. Under this order, if the pipeline chooses to become an open access carrier, end use customers and local distribution companies will be able to negotiate for their own gas supplies directly with producers or marketers, thus paying the pipeline only a transmission charge. To help pipeline companies to move away from the gas merchant function, the FERC will allow pipelines that opt for the transportation program to make certain payments to producers to extinguish producer take-or-pay claims, the cost of which can be

included in the pipelines' rates. Similarly, the pipelines' existing customers can reduce their contract purchases in steps to zero during a five-year period. Under this broadened access provision, pipelines under FERC jurisdiction must transport gas for others on a non-discriminatory basis.

Pipelines were given until June 30, 1986 to open their systems or lose their right to transport gas under existing transportation programs. This deadline was subsequently extended to January 1, 1987. Canadian exporters are greatly disadvantaged by the delay in implementing the order, because of the effect this has on their ability to gain access to new markets. Also their ability to retain their present share of existing markets is hampered, as interstate pipelines, in an effort to reduce take-or-pay obligations to domestic producers, increase takes of domestic gas at the expense of imported gas.

Also under Order 436, FERC will provide expedited certification procedures for new facilities needed to provide new service if the applicant agrees to fully bear the risk of the new facilities and agrees to abide by the "open access" requirement of Order 436, and if the applications are unopposed. New projects to transport Canadian gas could benefit from this procedure.

In June 1986, FERC issued Order 451 which replaces the myriad of ceiling prices for so-called "old" natural gas (low cost gas still regulated under the NGPA) with a single national ceiling price of $ US 2.57 per million Btu, to be adjusted for inflation. The intent of the order is to facilitate the production and marketing of U.S. "old" gas reserves which might otherwise not be produced. The order provides a mechanism for the renegotiation of prices in contracts for "old" gas up to the new ceiling level and also provides for the transportation of "old" gas on pipelines without the pipelines having to become "open access" systems under Order 436. Order 451 could therefore result in further delay in the implementation of "open access" transportation by some pipelines which may wish instead to transport "old" gas released from contract as provided for under this order.

It is estimated by the U.S. Department of Energy that Order 451 will result in the production of at least an additional 340 billion cubic metres (12 Tcf) of "old" natural gas in the U.S. over the next fifteen to twenty years due to the higher prices which would be available to this category of gas. The impact that this might have on Canadian exports is difficult to assess. On the one hand, assuming there is no change to the supply of high cost gas and to the total U.S. demand for gas, it could reduce the requirement for Canadian gas to about one-half of our projected level. On the other hand, the additional supply of gas (which would be mostly low cost gas) could have the effect of reducing the price for all gas (including gas imported from Canada) resulting in a higher demand for gas and lower production of high cost gas, such that our total projected level of exports could still be accommodated. The impact on export volumes, if any, would not likely be felt until after 1990. At that time the American market is expected to be more buoyant as a result of generally lower U.S. deliverability.

With respect to other regulatory developments, recent findings by FERC Administrative Law Judges have recommended that U.S. pipelines be allowed to pass through to their customers the costs of imported Canadian gas on an "as-billed" basis. That is, demand charges (fixed monthly charges) included in Canadian export contracts would be permitted as part of the demand charge component in the importing pipeline's rates. Notwithstanding these recent recommendations, there remains considerable opposition in the U.S. to the "as-billed" treatment of imports. At the time of writing this report, FERC had not yet ruled on this issue.

From a Canadian perspective, these recent regulatory changes have added greatly to the uncertainty over export volumes and future export projects.

5.5.3 Natural Gas Exports Outlook to 1990

Our assessment of exports reflects our view that the U.S. requirement for supplemental supplies of natural gas will be about 39 billion cubic metres (1.4 Tcf) in 1990. On the demand side, we see very little change in total U.S. natural gas demand over the next few years from the present level of about 481 billion cubic metres (17.0 Tcf) annually. On the supply side, we do not expect reserves additions in the U.S. to keep pace with demand, with the result that the current deliverability surplus should be largely eliminated by 1990. If the low level of drilling activity currently being experienced in the U.S. were to persist for several years, the deliverability surplus would be eliminated sooner than expected, resulting in a higher level of Canadian exports than is presently projected.

Natural gas exports, which had lost market share to United States gas in recent years, regained some of that

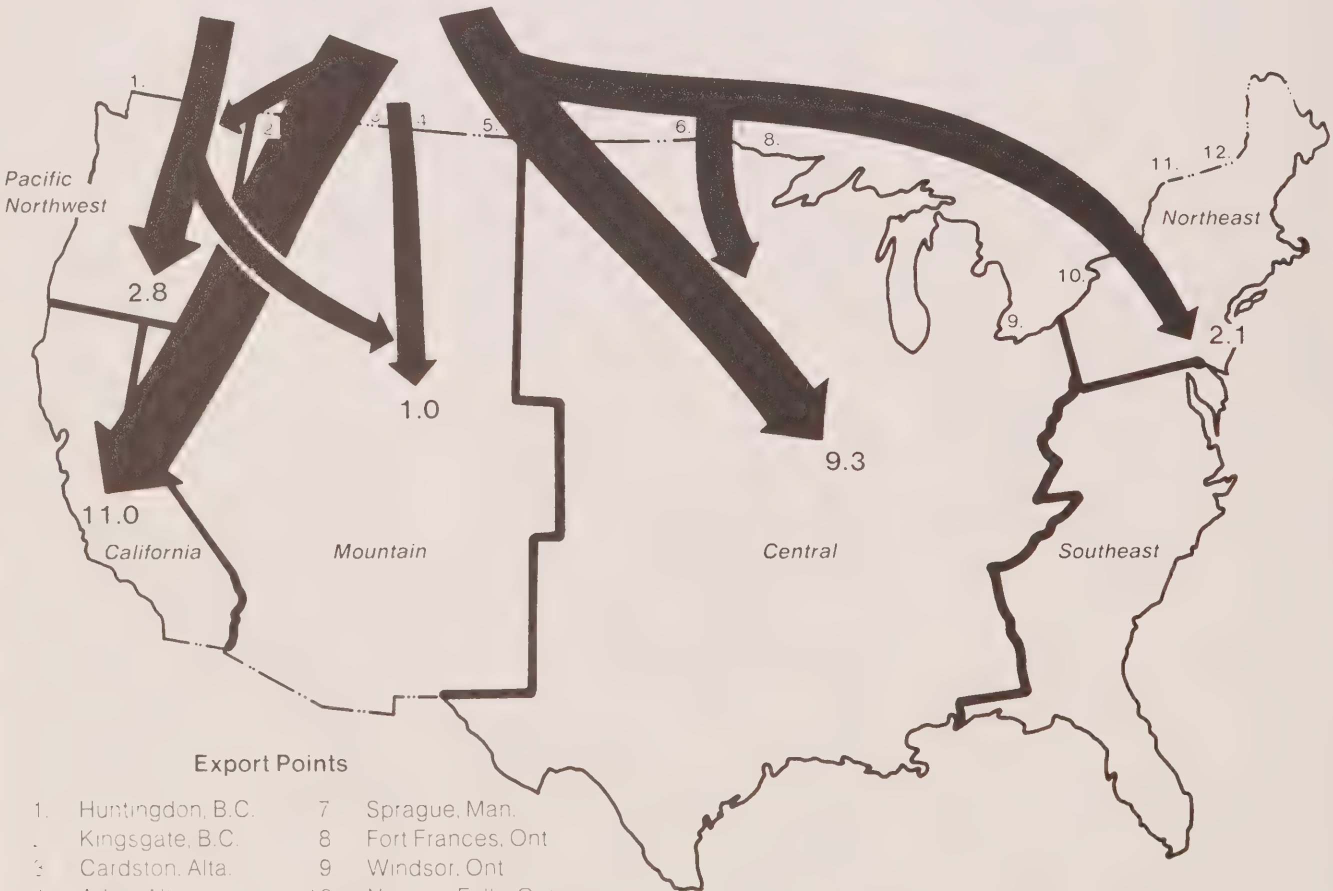
market in 1985, as exporters moved to more competitive pricing under buyer/seller negotiated export arrangements. Exports in 1985 were 26.2 billion cubic metres (925 Bcf), 5.4 percent of the total U.S. gas market. They were 21.4 billion cubic metres (755 Bcf), 4.2 percent of the market, one year earlier. However, even at the 1985 level, exports were still below levels attained in the middle 1970s, and were only one-half of the volume authorized.

The precipitous decline in world oil prices in 1986 has had its impact on U.S. gas markets by encouraging large industrial users and electric utilities with dual fuel capability to switch to lower cost residual fuel oil. U.S. natural gas prices, particularly prices for gas sold in the short-term (spot) market, have responded by declining to levels competitive with residual fuel oil. This in turn has had the effect of backing out higher priced, long-term supplies or "system gas", including gas exported from Canada.

Canadian exports are not expected to exceed 22.6 billion cubic metres (798 Bcf) in 1986, or about 4.6 percent of the total U.S. market. Canadian export prices are presently constrained by export floor prices which are based on regulated domestic prices. They should become more market responsive as a more flexible and market-oriented

Figure 5-8

United States Regional Natural Gas Markets and Canadian Export Flows (1985)[1]



Export Points

1.	Huntingdon, B.C.	7	Sprague, Man.
2.	Kingsgate, B.C.	8	Fort Frances, Ont
3.	Cardston, Alta.	9	Windsor, Ont
4.	Aden, Alta	10	Niagara Falls, Ont.
5	Monchy, Sask.	11	Cornwall, Ont
6	Emerson, Man	12	Philipsburg, Que

1 Figures shown by the arrows are 1985 export volumes in billions of cubic metres

pricing regime is introduced in Canada. Therefore in 1987, Canadian exports should regain their level of 1985. Attainment of these export levels will also depend upon gaining improved access to the interstate direct sales market which is presently dominated by U.S. short-term sellers. This will happen as more U.S. pipelines become "open access" transporters under FERC Order 436.

Beyond 1987, increased levels of exports are expected as the U.S. deliverability surplus begins to wane. Our approach was to examine both the implications of the overall United States gas balance and the prospects for specific markets being served by existing licences in preparing an outlook for each major regional U.S. market. The results are shown in Appendix Table A5-14 and Figure 5-8.

5.5.4 *Regional Market Considerations*

Historical and projected Canadian shares of the major United States regional markets are summarized in Table 5-4.

Pacific Northwest

Some 48 percent of the natural gas consumed in the Pacific Northwest region of the United States originates in Canada primarily from producing fields located in British Columbia. The main Canadian exporter to this region is Westcoast and the principal U.S. buyer is Northwest Pipeline Corporation (Northwest). Westcoast is also authorized to export Alberta-sourced gas through the pipeline facilities of Alberta Natural Gas Company Limited (ANG) in Canada and Pacific Gas Transmission Company (PGT) in the United States, which interconnects with Northwest.

During the early 1980s this market lost substantial natural gas volumes due to the recession and competition from electricity and residual oil, but signs are that the market is beginning to stabilize. Total gas demand in the region is up about 15 percent from the levels of two to three years ago, largely because of fuel switching from oil to gas. Recent low oil prices have started to reverse this trend but gas prices are responding quickly thereby limiting the loss of market to oil.

The capacity of Northwest to deliver U.S. produced natural gas into the region is limited, being about 1.4 billion cubic metres (49 Bcf) less than the current annual market demand. Consequently, Canadian gas has a market which is less susceptible to competition from low cost U.S. gas but is still subject to competition from high sulphur residual oil. To retain and expand its share of the market, Canadian gas will have to be competitively priced with residual fuel oil.

Because of proximity to the market and the presence of ample Canadian pipeline capacity, Canadian exporters are well positioned to serve this market. Our expectation is that Canadian gas will regain its traditional 70 percent share of the market by 1990, with annual sales of approximately 4 billion cubic metres (141 Bcf).

California

California remains the largest single market for Canadian natural gas exports, accounting for approximately 42 percent of exports in 1985.

Table 5-4

Canadian Natural Gas Exports to United States

History and Projections

(Percent is Canadian supply as a percentage of regional U.S. natural gas consumption; volumes in billions of cubic metres)

Region		History 1965	History 1975	History 1985	Projection 1990
Pacific Northwest	- percent	68.9	70.8	47.8	68.8
	- volume	3.2	5.5	2.8	4.0
California	-percent	9.0	20.8	23.2	24.2
	- volume	4.3	10.8	11.0	11.5
Mountain	- percent	8.8	11.4	4.9	7.8
	- volume	1.8	3.1	1.0	1.6
Central	- percent	0.7	1.9	2.9	3.7
	- volume	2.1	7.1	9.3	11.9
Northeast	- percent	0.3	0.6	3.3	13.8
	- volume	0.1	0.3	2.1	8.7
Total United States	- percent	2.7	4.8	5.4	7.7
	- volume	11.5	26.8	26.2	37.7

Note: The numbers in this table have been rounded.
Source: Appendix Table A5-7

Alberta gas supplies about 40 percent of the gas consumed in Northern California. The Canadian exporter is A&S and the U.S. importer, PGT. The ultimate buyer of the gas is Pacific Gas and Electric Company (PG&E), a major San Francisco utility and the owner of A&S and PGT.

Alberta gas is exported by Pan-Alberta under the Western Leg "prebuild" arrangement to Southern California. The routing of this export starts with Foothills Pipeline (Yukon) Limited and Nova, An Alberta Corporation. It next enters the ANG system and moves from there to the PGT system (as do Westcoast and A&S volumes). The gas continues in the PGT system to the Northwest system, where by displacement equivalent volumes are made available to El Paso Natural Gas Company (El Paso) for subsequent delivery to Southern California Gas Company (SoCal). As a result of this complex transportation arrangement, Canadian gas exported through the Western Leg has a high average delivered cost. Nevertheless, Canadian exports to this market were at authorized levels in 1985, with Canadian gas accounting for about 8 percent of total gas consumption in Southern California.

The demand for natural gas in California has declined in recent years because of an abundance of hydroelectric power, and the start up of the Diablo Canyon and San Onofre nuclear plants, reducing gas used for power generation. The decline appears now to have levelled off.

The primary competition to Canadian gas in both northern and southern California is gas supplied by El Paso,mainly from Texas and New Mexico. El Paso sells its own gas to SoCal and PG&E under long-term contracts and transports gas for other producers selling to the two utilities through a monthly spot market bidding system. In addition to selling gas under long-term contracts, Canadian exporters have been active participants in the monthly spot market and have been able to maintain their share of the market despite stiff competition.

Our projection is for Canadian gas to maintain its present 23 percent share of the total California market with exports of about 11.5 billion cubic metres (406 Bcf) per year. However, the possibility does exist for a substantial increase in volume as and when any of the pipelines proposed to serve the enhanced oil recovery projects in central California are constructed. The current situation of low world oil prices makes these projects very uncertain.

Mountain

Canadian gas exported from British Columbia and Alberta reaches the U.S. Mountain region via the Northwest and PGT systems, as well as directly from Alberta to the Montana Power Company. This region is Canada's smallest market accounting for only 4 percent of 1985 exports.

The total demand for natural gas in this region has declined by 25 percent in the past ten years partly as a result of conversions to coal and permanent plant closures. Our outlook is for this market to remain depressed with limited opportunities for increased sales. The forecast share of the market is approximately 8 percent in 1990, compared to 4.9 percent in 1985, which represents an increase in exports of 0.6 billion cubic metres (21 Bcf), to an annual level of around 1.6 billion cubic metres (56 Bcf).

Central U.S.

The Central region is the largest U.S. natural gas consuming region and is our second largest market (after California) accounting for 36 percent of exports in 1985.

Although substantial volumes of Canadian gas are consumed in this region, our share of consumption ranges widely from about 5 percent in Illinois to 20 percent in North Dakota. The eastern part of the region is characterized by large residential and industrial consumption. Price competition from low sulphur, residual oil is intense in the industrial sector. The western part of the region has a smaller industrial load which faces competition from high sulphur residual oil and coal. As with the Mountain region, gas demand has been declining in recent years, but at a slower pace. This region is also the largest customer for U.S. spot gas consuming approximately 10.3 billion cubic metres (364 Bcf) in 1985.

Natural gas from Alberta is exported to this region by TransCanada at Emerson, Manitoba to a number of United States pipelines: Great Lakes Gas Transmission Company, Midwestern Gas Transmission Company, ANR Pipeline Company and Natural Gas Pipeline Company of America. Exports at Monchy, Saskatchewan by Pan-Alberta via the Eastern Leg of the Foothills system to Northern Border Pipeline Company are delivered directly or by exchange to three U.S. pipelines: Northern Natural Gas Company, Panhandle Eastern Pipeline Company and United Gas Pipeline Company. Canadian gas is also sold through Emerson and Monchy by Consolidated Natural Gas Limited and ProGas Limited.

ICG Transmission Holdings Limited exports small volumes at Sprague,

Manitoba and re-imports at Rainy River, Ontario. Gas is distributed to several Ontario communities, and the remaining volumes are then exported at Fort Frances, Ontario to serve some small communities in northwestern Minnesota, and Boise Cascade, a pulp and paper plant at International Falls, Minnesota. Approximately one-half of this market has been lost to coal and wood in the past few years.

The loss of industry to the southern and western states which has occurred over the past decade, coupled with conservation, has eroded the industrial market base, severely limiting the prospects for renewed market growth. This loss of market has resulted in a situation of excess capacity on U.S. pipelines serving the region. The excess capacity has provided U.S. producers and marketers with a natural outlet for surplus supplies making this region the most competitive gas market in the country.

The competitive gas situation plus competition from oil and coal is expected to limit growth of exports at least until the late 1980s when it is expected that lower U.S. production will provide opportunities for market share expansion. Our outlook is for a modest increase in market share from 2.9 percent in 1985 to about 4 percent in 1990, with exports attaining an annual level of around 11.9 billion cubic metres (420 Bcf) by 1990.

Northeast

While accounting for only 13 percent of total United States natural gas consumption, the Northeast region has exhibited a steadily rising demand for gas, growing by almost 30 percent in the past ten years. Gas consumption in the Northeast has been accelerating largely as a reaction to the oil shocks of the 1970s. Moreover, with gas presently holding a 19 percent share of this energy market, compared with 25 percent for the U.S. as a whole, the region is considered to hold good prospects for continued growth of gas demand.

Because of its geographic position at the end of the U.S. interstate pipeline system, the Northeast generally pays more for its gas and is exposed to more frequent supply curtailments than any other region. The gas market, which is largely residential and commercial, is less exposed to competition from low cost residual oil and there is thought to be a large potential heating demand which could be served with the existing distribution infrastructure but is not being served because of the lack of firm winter supply. Also, there is a large amount of oil-fired electricity generation in this region which could be converted to gas if gas were competitively priced. Furthermore, new electricity generation capacity will be required in the 1990s, part of which could be gas-based.

Natural gas is exported to the Northeast at Niagara Falls, Ontario by Sulpetro Limited to Transcontinental Gas Pipeline Corporation and by TransCanada to Boundary Gas Incorporated. Some of ProGas' exports at Emerson, Manitoba reach this region through displacement arrangements with U.S. pipelines.

As well, Niagara Gas Transmission Limited exports at Cornwall, Ontario to St. Lawrence County in northern New York state and TransCanada exports to northern Vermont at Philipsburg, Quebec. These border markets are primarily residential and commercial and the load is highly temperature sensitive. The prime competition is fuel oil and to a growing extent wood.

Canadian gas presently accounts for only 3.3 percent of the natural gas consumed in this region. This could grow to nearly 14 percent by 1990, 8.7 billion cubic metres (307 Bcf) annually, if all of the exports authorized as a result of the Board's 1983 Gas Export Omnibus decision started to flow. Notwithstanding the demise of the U.S. Niagara Interstate Pipeline System project, which was to have carried the bulk of the new exports into this market, it is likely that this region will continue to demand increasing quantities of firm supplies of gas. Canada is strategically placed to provide such service. In this regard, several proposals have been advanced to provide new service to this region which would include new exports of Canadian gas either directly or by displacement with U.S. gas. We have assumed that one or more of these projects involving Canadian gas will proceed but that appreciable volumes will not begin to flow before late 1988 at the earliest.

5.5.5 Exports Under Short-Term Orders

In November 1985, the Government of Canada removed volume restrictions on short-term (24 month) natural gas export orders and simplified and expedited the approval procedure. Short-term exports remain subject to a floor price similar to that imposed on licensed exports. While numerous short-term export orders have been issued, most of the volume is presently unable to move to market either because it must await more interstate pipelines becoming "open access" transporters under FERC Order 436, or because the regional reference price

has not been competitive with prevailing spot market prices in the U.S.

Because of the highly uncertain nature of short-term exports (most are interruptible sales, with no minimum take requirement and subject to monthly price redetermination) we have not attempted to forecast these sales. However, we believe that notwithstanding the present constraints on access to U.S. interstate pipelines and export floor price restrictions, Canadian producers and exporters will play an increasingly important role in the burgeoning U.S. spot market.

Based on our projections of domestic requirements and presently licensed exports, we estimate that approximately 24 billion cubic metres (847 Bcf) of annual spare pipeline capacity for exports presently exists. This declines to approximately 9 billion cubic metres (318 Bcf) in 1990 under our demand projections. It assumes that additional pipeline capacity is installed for use in 1988, when additional capacity seems likely to be needed on TransCanada to meet projected domestic requirements. Approximately 70 percent of the spare capacity exists on export pipelines presently served by Alberta-produced gas. The projection of spare export pipeline capacity is shown in Table 5-5.

We emphasize that while substantial spare export capacity is available at times during the year, capacity limitations during peak winter periods are likely to preclude additional exports at some export points during periods of peak demand. Furthermore, if licensed exports were to be taken at full authorized levels, the spare capacity would be virtually eliminated.

5.5.6 Longer-Term Outlook

The outlook for U.S. natural gas markets and the requirement for imports in the longer term depends on a number of factors, notably the course of world oil prices and the response to them of supply and demand for natural gas. Most existing studies of the longer-term prospects for U.S. gas markets are based on world oil price projections developed before the oil price collapse of early 1986. These oil price projections are similar to or higher than the high price projection used in this report. The consensus is that, should such a relatively high world oil price prevail, American natural gas import requirements could rise in the 1990s and remain substantial, as greater opportunities would exist for the substitution of oil by natural gas. The export outlook for the next few years described in this Section is consistent with such a high oil price scenario. It follows that under our high price scenario the demand for imported gas to the U.S. is likely to remain strong and this will provide the incentive to Canadian producers to find and develop the reserves contained in our high price projection of Canadian supply.

It can be expected that under our low oil price scenario the longer-term prospects for exports of Canadian gas would be lower. Furthermore, under such a scenario incentives to find and develop substantial new supplies of gas in both Canada and the U.S. would not exist. Given that a low oil price scenario is consistent with abundant energy supplies, there would be less opportunities for inroads by natural gas in competitive energy markets.

Conclusion

In conclusion, we expect Canadian natural gas exports to maintain or moderately improve their share of the market in all U.S. regions where Canadian gas is presently consumed, but that the opportunity will

Table 5-5

Projected Spare Canadian Export Pipeline Capacity[a]

(Billions of Cubic Metres)

	Export Point Served [b] By British Columbia Gas	Export Point Served [c] By Alberta Gas	Total
1986	5.9	18.0	23.9
1987	5.6	12.4	18.0
1988	4.8	9.7	14.5
1989	3.7	6.5	10.2
1990	3.0	6.4	9.4

[a] Additional capacity for exports above the projections contained in this report. Only one estimate is shown; there is little difference between low and high cases.
[b] Includes Huntingdon, B.C. (some Alberta gas may be exported at Huntingdon).
[c] Includes Kingsgate, B.C. and export points to the east.

exist in the late 1980s to significantly increase our market share as American domestic deliverability is expected to decline. We anticipate that the improvement in market share will be greatest in those regions which are furthest from the major U.S. producing regions and where U.S. pipeline capacity is more fully utilized, specifically the Pacific Northwest and the Northeast.

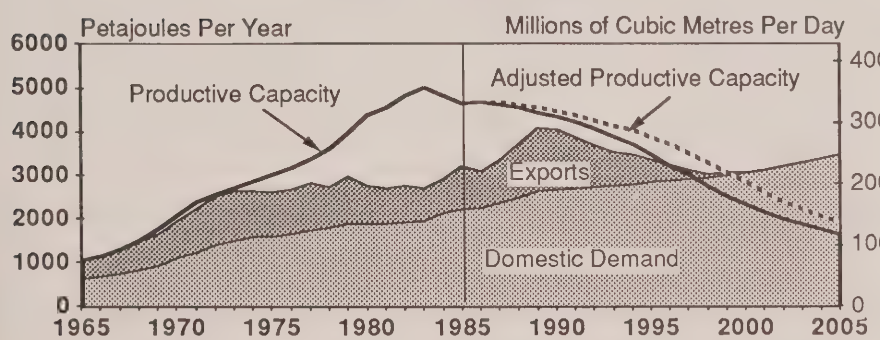
5.6 Supply/Demand Balances

Figure 5-9 compares the productive capacity projections with the projections of domestic and export demand for the two price cases. It shows that productive capacity adjusted for the effect of capacity not previously used is expected to meet total projected demand up to and including the year 1999 for the low price case and the year 2002 for the high price case. These estimates are detailed in Appendix Table A5-8.

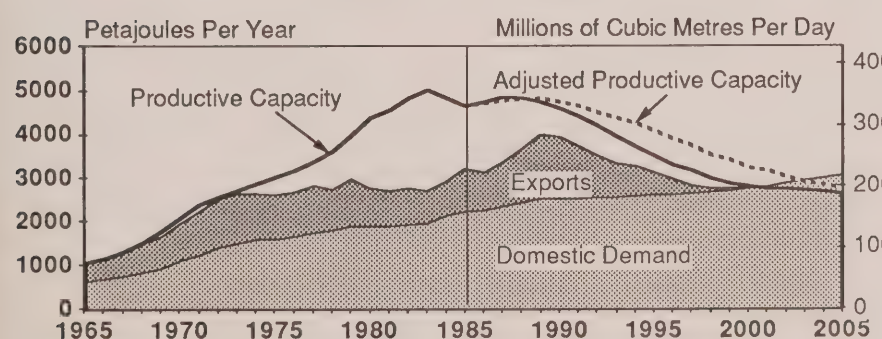
The figures show that there is room, in the high price case, for additional exports during the study period. However, it is quite clear that frontier gas supplies will be required early in the next century to satisfy projected domestic requirements. Evergreening of existing export authorizations and/or expectations of future export licences of a significant nature will likely need to be supported by gas reserves outside the conventional producing areas.

In the high price case a slightly higher productive capacity or lower demand than projected, occurring at about the time a supply deficiency is indicated, could result in a later supply-demand cross-over than shown. Such is less likely in the low price case because of the steeper decline in productive capacity at cross-over. Prices higher than our price projection, by increasing supply (discussed in Section 5.4) and depressing demand could also delay the date at which cross-over occurs.

Figure 5-9
Natural Gas Supply and Demand Conventional Areas Low Price Case



High Price Case



Source: Appendix Table A5-8

Chapter 6
Crude Oil and Equivalent

In this chapter, we examine the extent to which Canada's oil resources can satisfy domestic demand for petroleum products. The discussion includes a review of the components of the oil resource base to illustrate their relative size and quality. The different supply sources are then discussed beginning with currently remaining established reserves and future reserves additions, followed by synthetic crude oil and bitumen from oil sands deposits, and the prospects for production from frontier areas - the Mackenzie Delta/Beaufort Sea, the Arctic Islands and the east coast offshore. Productive capacity is included in the review of each component. After reviewing the total supply of crude oil and equivalent, we discuss petroleum product balances and refinery feedstock requirements. This is followed by a discussion of oil supply/demand balances and export markets for heavy crude oil. We conclude the chapter by discussing some of the implications of our projections for Canada's major oil pipelines.

6.1 Resources

We define the crude oil resource base as the total quantity of hydrocarbons, known or inferred to exist in reservoirs or deposits from which crude oil or its equivalent may be obtained. No allowance is made in estimating the size of the resource base for the proportion which may prove physically or economically unrecoverable. Only part of the resource base will ultimately constitute supply, depending on geological, technological and economic factors.

Canada's oil resource base can be divided into conventional crude oil, which constitutes about ten percent of the total resource base, and bitumen, which constitutes the remaining 90 percent. Conventional crude oil is capable of flowing naturally into a wellbore whereas bitumen is a tar-like substance which generally will not flow out of the deposit in which it occurs.

The conventional crude oil resource base can be divided into the resource base in the conventional producing areas and that in frontier regions. Each of these constitutes about five percent of the total resource base according to current estimates. Because our knowledge of the resource base increases as exploration advances, we have a greater knowledge of the conventional oil resource base in the conventional areas than we have of that in the frontier regions where its size is still quite uncertain.

Exploration in conventional areas is in a mature state and we estimate that some 85 percent of the original conventional oil resource base in these areas (i.e. before any production) has already been discovered. Only about a third of this original base is recoverable; the recoverable component constitutes reserves and potential reserves additions. The conventional oil resource base in the conventional areas is small relative to the total resource base, but it accounts for about 78 percent of current total productive capacity of crude oil and equivalent.

The resource base of conventional oil in frontier areas is estimated to be similar in size to its counterpart in conventional areas, but its current contribution to productive capacity is very small. Because the resources are offshore or in the Arctic areas their development will be relatively expensive. As a result the economic viability of the development of discovered resources will be much more sensitive to reservoir size and productive capacity than is the case in the conventional areas. The assessment of the resource potential of the frontier areas is carried out by the Geological Survey of Canada (GSC). This is based on a probabilistic methodology which incorporates both objective data and informed geological opinion.

The frontier regions are still relatively unexplored and only some ten percent of the estimated resource base has so far been discovered. Table 6-1 shows estimates of the physically recoverable oil, discovered to date, designated "discovered resources". These estimates were taken from the 1985 annual report of the Canada Oil and Gas Lands Administration (COGLA). The concept of discovered resources is different from the Board's concept of established reserves in that estimates of discovered resources are not constrained by economic considerations.

The resource base of bitumen is very large but contributes only

Table 6-1

COGLA Estimates of Discovered Resources of Crude Oil Frontier Regions

	(Millions of Cubic Metres)
Mackenzie/Beaufort Area	183.1
Arctic Islands	65.7
East Coast Offshore	205.1

Notes:
The numbers in this table have been rounded.

Discovered resources are estimates of the quantities of crude oil or natural gas potentially recoverable from known reservoirs, but of uncertain economic viability.

about 16 percent to current total productive capacity of crude oil and equivalent. The bitumen occurs in several very large deposits in Alberta and each of these deposits has its specific challenges with regard to extraction. Two large mining plants (Suncor and Syncrude) are currently in operation in that part of the Athabasca deposit close to the surface. The bituminous sand is recovered from open pits, the bitumen and sand are separated by a hot water process, and the bitumen is then upgraded by refinery processes to a synthetic light crude oil.

Smaller scale in situ oil sands projects are also in operation. These projects use steam injection which mobilizes the bitumen by increasing its temperature. The mobilized oil can then move to a wellbore and be pumped to the surface. This process has been successfully implemented in several projects in the Cold Lake deposit, but is less suitable in other deposits where the bitumen is too viscous to respond to steam injection. In the Peace River deposit this problem has been solved by injecting steam into a thin water bearing zone which underlies the bitumen.

Production from in situ projects is currently not upgraded; the produced bitumen is mixed with pentanes plus (a very light oil derived for the most part from natural gas processing) to thin the bitumen making it suitable for pipeline transportation.

Though currently available technology is capable of developing a sizeable portion of our bitumen resources, it is very expensive. Continuing progress appears likely in both extraction and upgrading technology. One upgrading process which shows promise is coal/oil co-processing. In this process coal and heavy oil are processed together in approximately equal quantities, on an energy equivalent basis, to yield a synthetic light crude or other more refined liquid fuel products. This process has the advantage that the oil supply is augmented through the liquefaction of coal of which Canada has an abundant supply. As a result of the research which has been carried out a group of private and government sponsors are proposing the construction of a prototype commercial scale plant in the U.S. A similar development in Canada is being pursued by CANMET, a research group within Energy, Mines and Resources Canada.

6.2 Established Reserves

Estimates of currently established crude oil reserves by province are shown in Table 6-2. These estimates are compiled by aggregating individual pool estimates made by Board staff. They were for the most part made before the recent fall in oil prices and are therefore considered more representative of the high price case than the low. However, since the effect of crude oil prices on established reserves is expected to be relatively small, no separate reserves estimate was attempted for the low price case.

Since 1982, reserves additions have exceeded production, arresting

Table 6-2

Remaining Established Reserves of Conventional Crude Oil

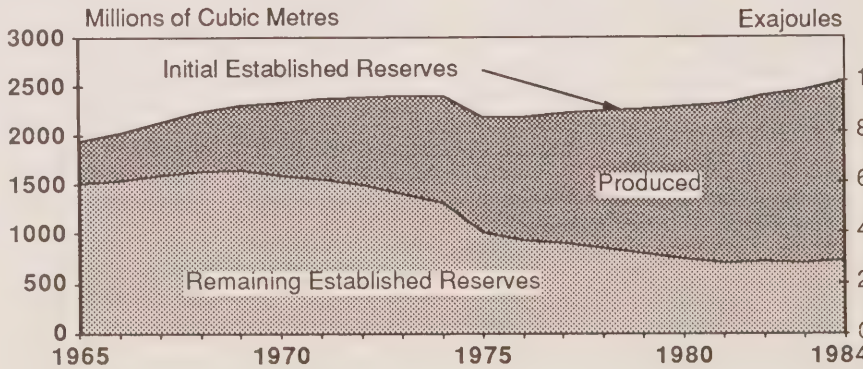
at 31 December 1984

(Millions of Cubic Metres)

Northwest Territories	35.2
British Columbia	18.6
Alberta	566.4
Saskatchewan	110.1
Manitoba	9.6
Ontario	0.8
Total Canada	740.7

Note: The numbers in this table have been rounded.
Source: Appendix Table A6-2

Figure 6-1
Established Reserves of Conventional Crude Oil Conventional Areas



Source: Appendix Table A6-1

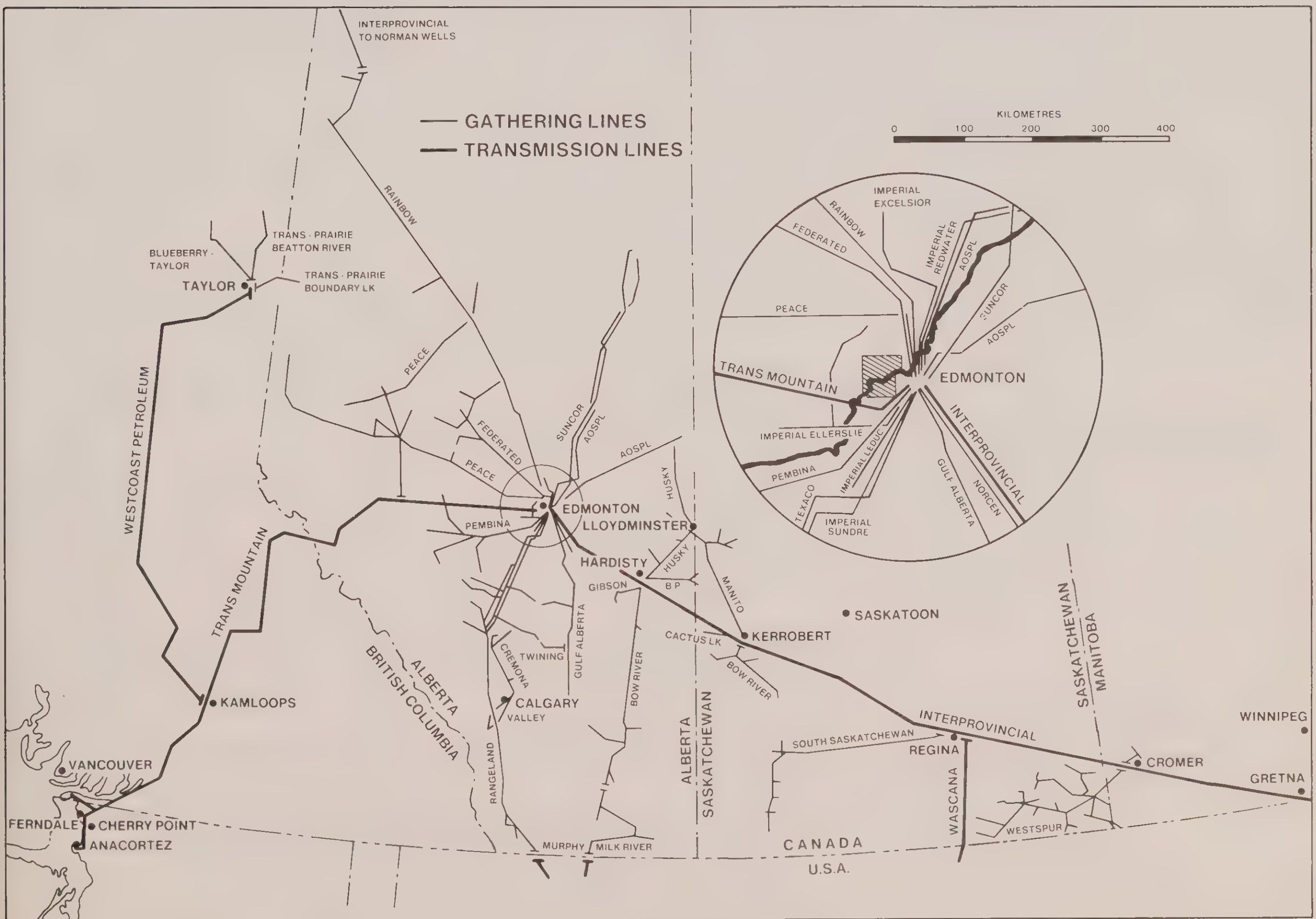
the sustained decline in remaining reserves which had occurred from 1969 to 1981 (Figure 6-1).

In the high price case the productive capacity from currently established reserves of light and heavy crude in total is projected to decline from 204 thousand cubic metres per day in 1985 to 20 thousand cubic metres per day in 2005. For the low price case the supply of light crude oil from currently established reserves is projected to be about two percent lower than that in the high price case and the supply of heavy crude oil about five percent lower. The reduction in supply for the low price case reflects expected earlier abandonment of producing wells, as these become uneconomic to operate sooner than they would under the high price case.

Appendix Table A6-2 shows the supply of heavy and light crude oil from currently established reserves by province, and Appendix Table A6-3 provides further detail on the production of individual pools and the supply by pipeline system. We aggregate pool production by pipeline system to provide a means of assessing pipeline utilization. Figure 6-2 shows the location of the major gathering and trunk pipelines which transport the crude oil from the producing fields to the refinery centres.

Figure 6 - 2

Major Crude Oil Gathering Lines



6.3 Reserves Additions and Ultimate Potential — Conventional Areas

Reserves additions consist of two components, appreciation of existing reserves and future discoveries. For our analysis we estimate appreciation of currently established reserves resulting from future enhanced oil recovery projects separately from all other reserves additions. The latter, which relate primarily to drilling activity, we place in a second category. These categories are discussed individually.

6.3.1 Additions from Enhanced Oil Recovery in Currently Established Pools

In this report enhanced oil recovery includes all recovery techniques other than those which utilize only the natural energy of the reservoir (termed primary recovery). Though there is some potential in established pools for reserves additions by further waterflooding (termed secondary recovery), the greatest potential for enhanced recovery is through the application of more costly methods, commonly referred to as tertiary recovery techniques.

For light oils less than 20 percent of the oil in place is recoverable by primary techniques. Recovery can be improved to more than 30 percent by secondary and tertiary techniques. For heavy oil, tertiary recovery may increase recovery from less than ten percent to more than 20 percent.

For light oil the most common tertiary technique involves the injection of a fluid that is miscible with the oil under reservoir conditions. In Canada this is usually a combination of natural gas liquids (NGL), ethane, propane, butanes and pentanes plus.

For heavy oils the most common tertiary process involves steam injection. An alternative thermal technique which is most suitable for thin zones in heavy oil pools is in situ combustion of part of the oil in the reservoir, achieved through air or oxygen injection. Other processes such as surfactant, alkaline and polymer-assisted waterfloods may be used for both heavy and light oil but are expected to provide only minor amounts of incremental oil over the projection period.

We have estimated technical and economic potentials for enhanced oil recovery, and projected reserves additions from this source. The technical potential is the estimated total incremental oil recovery from established pools using what is judged to be the most technically appropriate process for each pool. The economic potential is the estimated incremental oil that could be economically recovered as judged by a comparison of social supply costs with our projected oil prices. (All social supply costs are estimated in 1986 dollars. For a discussion of social supply costs see Chapter 5.)

Our estimates of social supply costs for enhanced recovery vary from project to project with $ C 100 per cubic metre ($ US 11 per barrel) being the minimum for both heavy and light oils. Social supply costs of oil from hydrocarbon miscible projects will, of course, vary with the costs of injected hydrocarbon materials and, for steam injection pro-

Table 6-3

Enhanced Oil Recovery [a]

(Millions of Cubic Metres)

	Waterflood	Miscible	Thermal	Other	Total
Low Price Case					
Technical Potential	179	271	265	30	745
Economic Potential	91	108	53	0	252
Total Additions 1985-2005	91	93	50	0	234
High Price Case					
Technical Potential	179	271	265	30	745
Economic Potential	91	136	95	9	331
Total Additions 1985-2005	91	116	82	9	298
Reference Case - September 1984 Report [b]					
Technical Potential	172	272	265	30	739
Economic Potential	90	115	169	9	383
Total Additions 1985-2005	90	115	102	9	316

[a] Technical and economic potentials are for enhanced recovery in pools discovered prior to December 31, 1984

[b] Potentials from the September 1984 Report have been adjusted to account for projects which were projected to come on stream between December 31, 1982 and December 31, 1984.

Source: Appendix Table A6-5

jects, with the cost of natural gas used to generate the steam. Based on our world oil price projections and transportation differentials, wellhead prices for light crude oil in western Canada are expected to rise from $ C 110 to 145 per cubic metre ($ US 12 to 17 per barrel) in the low price case and from $ C 125 to 220 per cubic metre ($ US 14 to 25 per barrel) in the high case. For heavy crude oil, wellhead prices are 10 to 20 percent lower reflecting quality differences and location.

Our estimates of technical and economic potentials and totals of reserves additions from enhanced oil recovery are given in Table 6-3.

In the low price case the economic potential for miscible flood projects is not much lower than in the high price case because it is assumed that the price of injection fluids will drop with the oil price, so that project profitability is less affected than otherwise would be the case.

Miscible flood projects already approved by the Alberta ERCB for implementation are listed in Appendix Table A6-10. This list is used as a guide in constructing the schedule of reserves additions for enhanced recovery of light crude oil in the high price case, shown in Appendix Table A6-6. In the low price case the projected schedule of reserves additions was reduced relative to the high price case in the early years of the review period, due to the reduced cashflow available for enhanced recovery projects and lower profitability of individual projects at that time.

For heavy oil the economic potential for reserves additions is also lower in the low price case than in the high price case. Again, however, the impact of lower oil prices is offset to some extent because the price of the natural gas, used in generating steam for thermal projects, is also lower. The projected reserves additions for enhanced recovery of heavy oil are shown in Appendix Table A6-7.

Included in Table 6-3 are the estimates of potentials and total additions over the same period in the reference case of the September 1984 Report. Technical potentials are essentially the same as previously, but, economic potentials are different primarily because our oil price projections are different. For the low price case the economic potentials are less than those in the September 1984 Report. For the high price case these potentials are equal to or less than those in the reference case of the September 1984 Report, except for miscible projects. The impact of the lower prices in the current projections is particularly severe on the economics of thermal projects. Total reserves additions for the review period are less than those for the reference case of the September 1984 Report in both price cases.

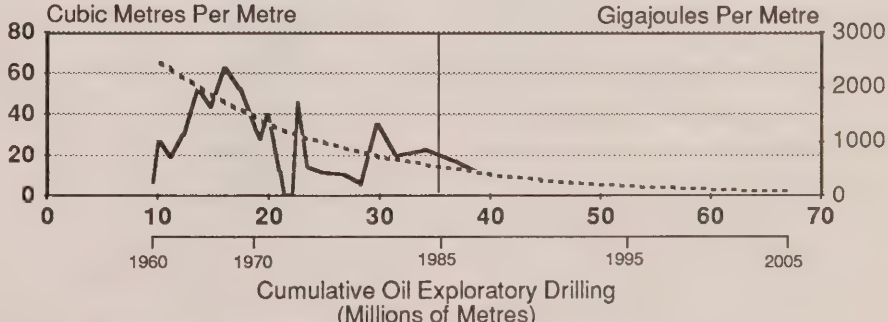
6.3.2 Additions Related to Drilling Activity

Crude oil reserves additions which relate to drilling activity include those from new discoveries, from any future appreciation associated with these discoveries (including that from enhanced oil recovery) and from incremental volumes resulting from appreciation of currently established reserves (excluding the enhanced oil recovery which was discussed above).

Our projections of reserves additions which result from future drilling are based on an extrapolation of the historical relationship between the rate of reserves additions and the amount of exploratory drilling carried out. Figure 6-3 illustrates this relationship for the Western Canada Sedimentary Basin.

The oil-directed exploratory drilling profiles, discussed in Chapter 5, were combined with the extrapolation illustrated in Figure 6-3 to develop the projections of oil reserves ad-

Figure 6-3
Relationship of Crude Oil Primary Reserves Additions Rate to Cumulative Oil Exploratory Drilling Conventional Areas



Note: Years shown for the projection period apply to the high price case only.

Source: Appendix Table A6-4

ditions resulting from drilling activity. Our estimate of the remaining potential for future reserves additions related to drilling is some 430 million cubic metres. Of this total, some 227 million cubic metres is estimated to be added between 1985 and 2005 in the low price case, and 313 million cubic metres in the high price case (Appendix Table A6-5).

The precipitous fall in world crude oil prices early this year resulted in a major reduction of exploratory drilling. This will result in a corresponding decline in reserves additions. For the low price case the reserves additions of light and heavy crude oil resulting from drilling operations are expected to decline sharply in the near term from 46 million cubic metres in 1985 to about 22 million in 1986 and 11 million cubic metres in 1987. In the high price case the expected reserves additions for 1987 are greater, at 17 million cubic metres. The rates of reserves additions projected for the later years of the forecast period, in both cases, reflect the depletion of the conventional oil resource base in western Canada.

For western Canadian conventional oil, we expect social supply costs in the $ C 110 to 150 per cubic metre ($ US 13 to 17 per barrel) range. These costs are the full-cycle costs of finding, developing, and producing the oil. If oil prices are low, industry can be expected to explore only those prospects promising larger discoveries. At higher prices, more prospects with smaller expected discovery sizes become attractive.

Details of expected additions from drilling activity for the two cases are found in Appendix Tables A6-6 and A6-7.

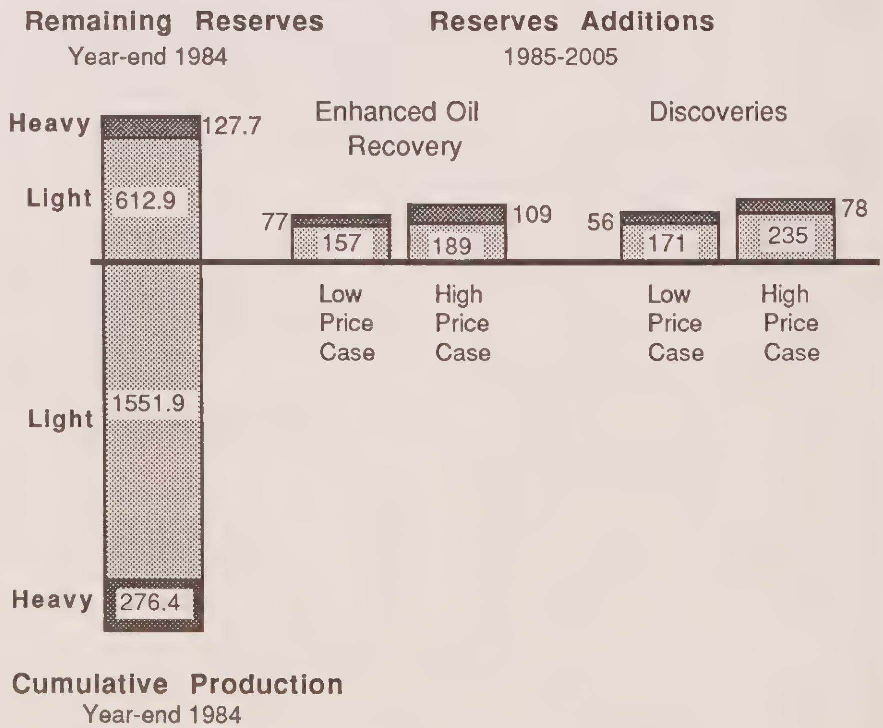
6.3.3 Ultimate Potential and Total Reserves Additions

The ultimate potential of crude oil in conventional areas is represented by the area under the curve shown in Figure 6-3. We estimate this potential to be 3750 million cubic metres, an increase of 120 million cubic metres over the estimate used in the September 1984 Report. Such an increase is consistent with the recent high level of crude oil reserves additions. Details concerning the ultimate potential are given in Appendix Table A6-5.

Our outlook for the reserves additions from each category is compared to established reserves in Figure 6-4. Our projection of these reserves additions by year is shown in Figure 6-5 together with the corresponding historical data.

We are projecting total reserves additions of light and heavy conventional crude oil during the review period of 460 million cubic metres and 610 million cubic metres in the low and high price cases respectively (Appendix Table A6-5). The estimate in the low case is some

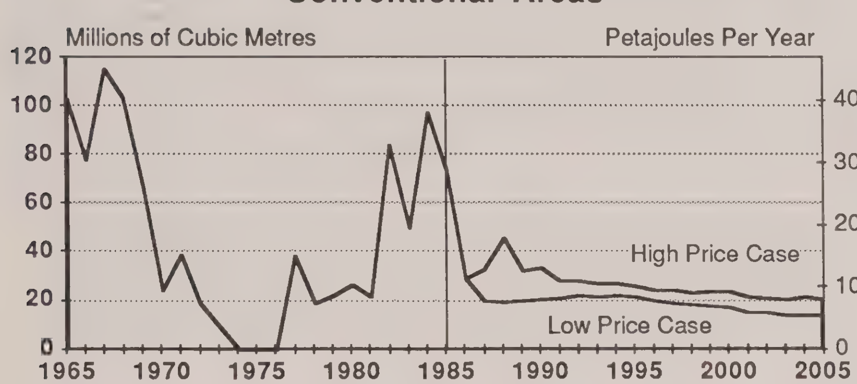
Figure 6-4
Reserves of Conventional Crude Oil Conventional Areas
Millions of Cubic Metres



Source: Appendix Tables A6-2 and A6-5

Figure 6-5

Conventional Crude Oil Reserves Additions Conventional Areas



Source: Appendix Tables A6-1, A6-6 and A6-7

120 million cubic metres less, and in the high case some 30 million cubic metres more than the reference case estimate for the same period in the September 1984 Report. The higher current projection for the high case reflects our more optimistic outlook for ultimate potential, based on the results of recent drilling activity.

In both price cases reserves additions are insufficient to replace production of conventional crude oil. This is reflected in the productive capacity projections (Appendix Table A6-14). In the low price case, the productive capacity from currently established reserves of conventional light and heavy crude declines from 204 thousand cubic metres per day in 1985 to 19 thousand in 2005, a reduction of 185 thousand cubic metres per day. The additional productive capacity from reserves additions over the review period amounts to only 44 thousand cubic metres a day in 2005, so that the net reduction in productive capacity over the review period is 141 thousand cubic metres per day. In the high price case the net reduction is 124 thousand cubic metres per day. Our assumptions for converting reserves additions to productive capacity are shown in Appendix Tables A6-8 and A6-9.

6.4 Synthetic Crude and Bitumen

The vast oil sands deposits of western Canada contain bitumen which is so viscous that it will not flow through a reservoir to a wellbore in its natural state. As noted in Section 6.1 two production techniques are being used commercially at the present time, open pit mining and in situ recovery.

Synthetic light crude oil produced by mining and upgrading at the Suncor and Syncrude plants currently contributes about 14 percent to the productive capacity of light crude oil and equivalent. Operation of the plants becomes uneconomic at world crude oil prices below about $ US 13 per barrel. At this price revenues are just sufficient to recover direct operating costs. To close down such plants is costly, hence operations are expected to continue as long as anticipated losses do not exceed the cost of closing down the plant. Although we have projected continued operation of these plants in both cases, in the low price case a major operational setback could cause operations to be discontinued as the additional investment for repairs may not be justifiable.

Our estimates of the social supply costs of new mining plants with upgrading are in the range of $ C 185 to 275 per cubic metre ($ US 21 to 31 per barrel) at the plant gate. This translates to a price of $ C 200 to 290 per cubic metre ($ US 23 to 33 per barrel) in Chicago. Such plants are only likely to be economic in the high price case and then only if they can be built at a cost towards the low end of our estimated supply cost range. No production from new mining plants is included in our projections. It appears more likely that future oil sands developments will use the in situ process which is amenable to small scale expansions which have lower financial risk than large scale mining projects. However, further additions to existing plants, the supply cost of which is expected to fall in the low end of our supply cost estimates, cannot be ruled out. Moreover, breakthroughs in the technology of mining and processing oil sands with concomitant cost reductions, could well lead to the construction of new plants in the latter part of the review period.

Recent oil sands developments have all involved the in situ process without upgrading to synthetic light crude. These developments were possible because of a growing market for heavy crude oil in the United States.

For bitumen produced by the in situ process we estimate that social

supply costs as low as $ C 70 per cubic metre ($ US 8 per barrel) at the plant gate can be achieved in the higher quality reservoirs. This cost compares with expected prices for bitumen at the plant gate in the 1990s of $ C 90 per cubic metre ($ US 10 per barrel) and $ C 140 per cubic metre ($ US 16 per barrel) for the low and high price cases respectively.

In the low price case we expect that only the higher quality in situ reservoirs will be developed during the review period and that development will be limited to those projects currently under construction. In the high price case the growth in the supply of in situ bitumen is expected to continue although during the next 2 to 3 years expansion is likely to be less than previously anticipated. Our projection in this case is an aggregation of supply from individual projects currently planned as shown in Appendix Table A6-11. We anticipate that in the high price case bitumen is likely to be constrained more by demand than supply (The prospects for exports are discussed in Section 6.8.). In this case, bitumen producibility amounts to 85 thousand cubic metres per day by 2005, three quarters of projected heavy oil production in that year.

We estimate the social supply cost for upgrading heavy oil or bitumen to a light synthetic crude oil at $ C 70 to 105 per cubic metre ($ US 8 to 12 per barrel), based on preliminary cost estimates for the Husky upgrader proposed for the Lloydminster area. The range of costs reflects the uncertainty of project costs and product yields. Several processes for upgrading are under development which could reduce these costs. One such process which shows promise is coal/oil coprocessing, discussed in Section 6.1.

We estimate total supply costs for in situ bitumen production and upgrading will be in the range $ C 140 to 230 per cubic metre ($ US 16 to 26 per barrel) which translates to a price of $ C 155 to 245 per cubic metre ($ US 17 to 28 per barrel) in Chicago. Consequently upgrading of bitumen to lighter synthetic crude is an economically viable option in the high price case. We have included for this case two new upgraders, one starting up in 1995 and the other in 1999, each with a capacity of 8000 cubic metres per day. However, given the very large oil sands resources, it is quite possible that either larger or more plants could be constructed. The Co-op upgrader now under construction at Regina and scheduled to start operation in 1988 is included in both cases.

The major oil sands and upgrading projects included in our two crude oil price scenarios are shown in Table 6-4.

6.5 Pentanes Plus

Pentanes plus is the lightest component included in supply of crude oil and equivalent. It is the heaviest of the natural gas liquids and as such is discussed further with other natural gas liquids in Chapter 7. Appendix Table A7-6 provides a plant by plant projection of production for the low price case and a summary of pentanes plus supply by pipeline for the high price case. The pentanes plus supply is included in our crude oil and equivalent supply projections in Appendix Table A6-14. Excluded from the quantities shown in the table are small amounts contained in NGL mixes for use in enhanced oil recovery schemes.

Pentanes plus is used as a viscosity reducing agent for conventional heavy oil and bitumen and as a refinery feedstock. It is also required for vapour pressure control of NGL moved on the IPL pipeline through

Table 6-4

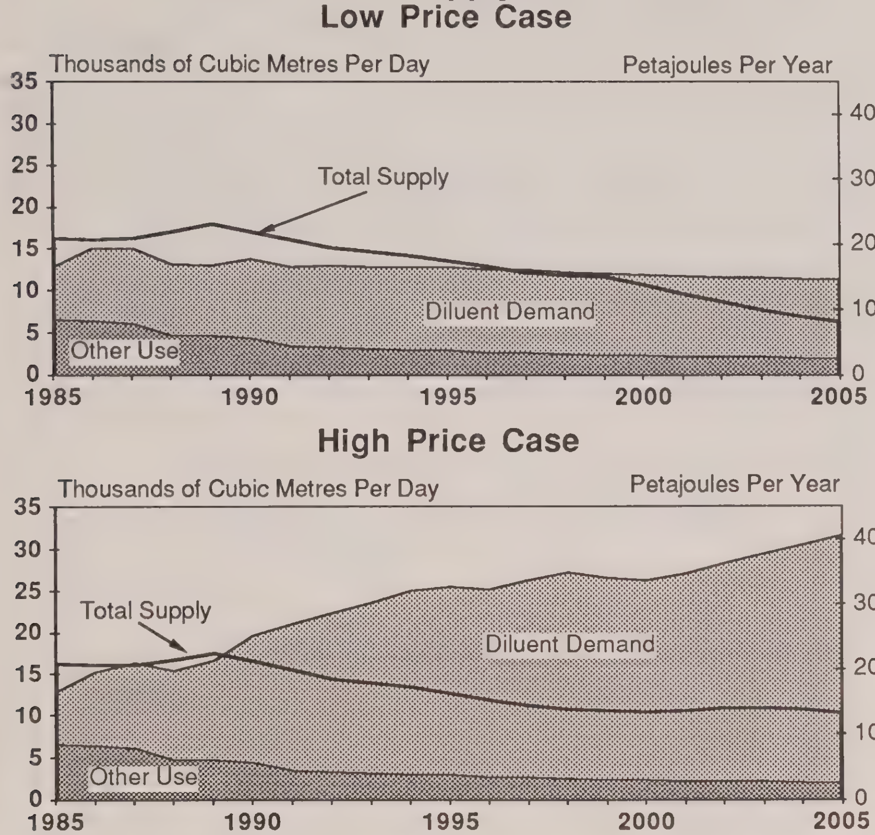
Timing of Major Projects

		Start-up Year	
	Size [a]	Low Price Case	High Price Case
Oil Sands Mining Plants			
Expansion of Syncrude	2.5	–	1991
Upgraders			
Co-op	8.0	1988	1988
Other	8.0	–	1995
Other	8.0	–	1999
Frontier Areas			
Hibernia	17.5	–	1995
Beaufort Sea	17.5	–	1996

[a] Thousands of Cubic Metres per Day.

Source: Appendix Table A6-14

Figure 6-6
Pentanes Plus Supply and Demand



Source: Appendix Table A6-14

low pressure storage facilities at Superior, Wisconsin.

The projected increase in the production of bitumen together with the anticipated long-term reduction in the supply of pentanes plus will result in shortages in pentanes plus supply in both price cases. These shortages are indicated by the supply-demand balances shown in Figure 6-6. Pentanes plus supply becomes deficient about 1997 in the low price case and about 1989 in the high price case.

A potential constraint on bitumen supply resulting from reduced availability of pentanes plus may be alleviated by recycling of diluent from eastern refineries to Alberta, importing pentanes plus, using light crude oil or refined naphthas as diluent, or upgrading heavy oil and bitumen in regional upgraders to the quality required for transportation. For our projections of productive capacity of crude oil and equivalent we assume that diluent requirements in excess of the supply of pentanes plus will be met by a light oil fraction (Appendix Table A6-14).

The Co-op upgrader under construction at Regina will not reduce diluent requirements unless a pipeline is built to return the diluent from Regina to the oil producing fields. The regional upgrader proposed for the Lloydminster area by Husky would reduce diluent requirements but would not commence operation before 1995 in our high price case.

6.6 Frontier Areas

The frontier regions are believed to have the geological potential for substantial levels of hydrocarbon production. Major crude oil discoveries have been made at Hibernia, offshore Newfoundland, and at Amauligak in the Beaufort Sea. Smaller accumulations have been found in the vicinity of these discoveries, as well as offshore Nova Scotia, in the Arctic Islands and in the Mackenzie Delta. To date there has been no production from any of these areas except for minor tanker shipments from the Bent Horn field in the Arctic Islands and from the Amauligak discovery. The Bent Horn shipments were intended to show the commercial feasibility of shipping crude oil out of the high Arctic by icebreaking tanker and may continue if profitable; the shipment from Amauligak was to facilitate an extended production test.

A development plan for the Hibernia field has been conditionally approved by the Canada-Newfoundland Offshore Petroleum Board. This plan includes construction of a fixed concrete base production platform which will accommodate drilling, production, injection and processing equipment as well as living quarters for 300 people.

The development plan provides for production from both subsea and platform wells; the crude oil would be transported from the wells in shuttle tankers. The earliest date of production would be 1992. Maximum production of about 17 500 cubic metres per day would be reached after two years, and would

be maintained for about eight years after which production would decline. Under the plan the pool would be abandoned after 20 years when the recoverable reserves, estimated by the operator at 83 million cubic meters, were produced.

The proposed production levels for Hibernia noted above are reflected in our high price projection. However, the starting date of production is uncertain and will depend on how soon an agreement can be reached between the operator and the two levels of government on fiscal and financial arrangements. In our high price case we assume 1995 as the first year of production. No production from Hibernia is included in the low price case, as operations would not be economic at projected supply costs. We estimate a social supply cost of $ C 150 to 180 per cubic metre ($ US 17 to 21 per barrel) for oil produced from Hibernia utilizing a fixed concrete production platform. This estimate does not include exploration or transportation costs. Equivalent prices in Chicago are $ C 165 to 195 per cubic metre ($ US 18 to 22 per barrel).

Although in the high price case we project production only from Hibernia, smaller fields elsewhere on the Grand Banks or on the Scotian shelf could also become productive before the end of the projection period, given appropriate technology probably associated with floating production systems.

Plans for production from the Beaufort Sea - Mackenzie Delta region are less advanced than are those for Hibernia. The discovery of the offshore Amauligak field in 1984, with reserves estimated by the operator in excess of 100 million cubic metres, has increased the possibility of early development in this area if world crude prices recover to levels in the neighbourhood of our high price case. For the Beaufort Sea we estimate a supply cost of $ C 100 to 160 per cubic metre ($ US 11 to 18 per barrel) which with transportation costs is equivalent to a Chicago price of $ C 170 to 230 per cubic metre ($ US 19 to 26 per barrel). Exploration costs, being sunk costs, are not included in this estimate.

In our high price projection, we assume production from the Beaufort Sea - Mackenzie Delta region starting in 1996 reaching a maximum level of 17.5 thousand cubic metres per day in 1997 which is maintained to the end of the review period. For this region we do not identify the sources of production, but would expect it initially from a larger offshore reservoir, with subsequent development of smaller fields both offshore and onshore. Our estimate of productive capacity from this region is obviously subject to considerable uncertainty.

We do not explicitly include production from the Arctic Islands in our projection; annual tanker shipments from the Bent Horn field may continue for an indefinite period, but would likely remain small in the context of total supply.

The major frontier projects included in our high price projection are shown in Table 6-4. In the low price case, our projection includes no new supplies from frontier sources.

6.7 Total Supply

Our projections for the total supply of crude oil and equivalent are summarized in Table 6-5 and shown in Figure 6-7. Complete details are given in Appendix Table A6-14.

Table 6-5

Productive Capacity of Crude Oil and Equivalent

	1985	1986	1987	1990	1995	2000	2005
(Thousands of Cubic Metres per Day)							
Low Price Case							
Light	204	204	194	163	123	100	81
Heavy	55	64	63	50	47	43	41
Total	259	268	257	213	170	143	122
High Price Case							
Light	204	205	195	165	132	150	128
Heavy	55	65	68	73	94	94	114
Total	259	270	263	238	226	244	242
Reference Case - September 1984 Report							
Light	190	178	169	162	182	171	157
Heavy	51	51	52	39	46	52	59
Total	241	229	221	201	228	223	216

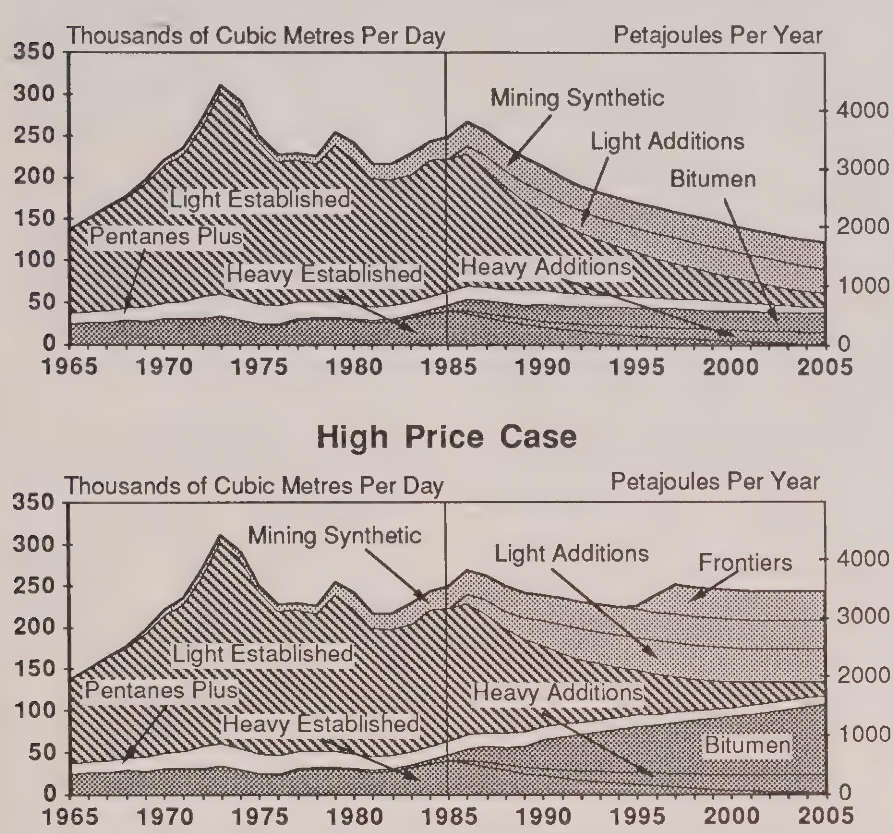
Note: The numbers in this table have been rounded.

Source: Appendix Table A6-14 and September 1984 Report.

Figure 6-7

Supply of Domestic Crude Oil and Equivalent

Low Price Case



As a result of the favourable climate for exploration and development that existed during the past few years, the total supply of crude oil and equivalent has increased rapidly since 1982. Much of the growth was in the productive capacity of bitumen but the production of conventional light crude oil, which had declined between 1973 and 1982, also increased, by about five percent between 1982 and 1985. We do not expect this trend in light oil production to continue in either of the oil price cases because of the advanced state of depletion of producing reservoirs.

In the low price case the supply of light crude oil and equivalent in 2005 is projected to be only about 40 percent of the level in 1985. The projection displays a continuous decline over the review period. New supplies from reserves additions of light crude oil and the Co-op upgrader are inadequate to offset the decline resulting from the depletion of currently established pools.

In the high price case we project larger reserves additions of light crude oil and include new supplies from two additional upgraders and the frontier areas. However, even these additional supplies are inadequate to completely offset the projected decline of light oil supply from currently established reserves. In this case the projected supply of light crude oil and equivalent in 2005 is 63 percent of that in 1985.

For heavy crude oil the situation is markedly different for the two price scenarios.

In the low price case the total supply of heavy crude oil, after an initial increase to a peak in 1986, gradually declines over the review period to a level in 2005 73 percent of that in 1985.

In the high price case the supply of heavy crude oil increases quite rapidly over the review period even though we include two additional upgraders which use heavy oil feedstock. The net supply of heavy crude after subtracting the quantities required by the new upgraders is still, in 2005, more than double the level in 1985. The reason for this growth is that oil prices in this case are sufficiently high that bitumen can be commercially produced by the in situ process at several large oil sands projects.

Included in Table 6-5 with our current projections for crude oil and equivalent are those for the reference case of the September 1984 Report.

Our current projections for the supplies of both light and heavy crude oils are higher in the near term than those shown in the September 1984 Report. Since the time of preparation of that report, drilling activity for conventional oil has been much higher than we anticipated, and development of bitumen production has also proceeded more rapidly.

In the longer term our current projections of supply of light oil and

equivalent for both price cases are lower than the previous reference case. This would be expected given current expectations of future oil prices.

For heavy oil we are projecting in the high price case a more rapid and extensive development of bitumen production than we projected for the September 1984 Report. However, in the low price case, our current projection of heavy oil supply is less in the long term than the previous reference case. Again, this would be expected given the much lower oil prices now envisaged.

6.8 Petroleum Product Balances and Refinery Feedstock Requirements

In Chapter 3 we assessed the prospects for oil use in Canada in terms of the total demand for refined petroleum products. In order to determine the implications of petroleum product demand for the supply and demand balances for crude oil, product demands must be converted to the corresponding requirements for refinery feedstocks in Canada. This is the subject of this section.

An assessment of the implications of petroleum product demands for crude oil needs in Canada requires an evaluation of the configuration of the Canadian refining industry and the role of exports and imports of petroleum products. Both of these are subject to considerable uncertainty.

For a number of years, Canadian refiners, in common with refiners around the world, have faced a series of rapidly changing circumstances including fluctuating feedstock costs, reduced demand for petroleum products and an altered product demand slate. Figure 6-8 displays how Canadian demand for particular petroleum products has changed over time.

In adapting to these new realities the industry has changed in a number of ways. This adaptation is often referred to as "refinery rationalization", a term which connotes one or more of refinery closings, refinery upgradings and, in some cases, construction of more efficient plants. Canada's refining industry has undergone significant rationalization, placing the industry in a better position to respond to current and prospective product markets and feedstock availability.

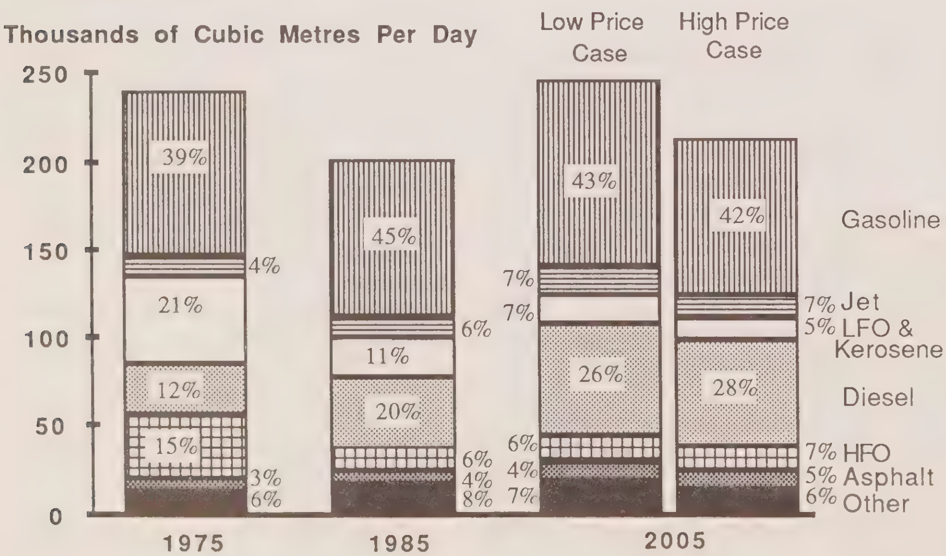
In 1980, there were 37 refineries operating in Canada with a combined distillation capacity of about 370 thousand cubic metres per day. By 1986, 11 refineries had closed and two others had been reduced in size, lowering capacity by 105 thousand cubic metres per day. During the same period two new plants came on stream and several others had small expansions. The decisions to construct the two new facilities were taken at a time of healthy demands for products. Over the period, Canada's refinery capacity experienced a net reduction of some 79 thousand cubic metres per day or 21 percent (see Table 6-6).

Table 6-6
Refinery Capacity

	As of January 1980	As of January 1986
	(Thousands of Cubic Metres per Day)	
Atlantic Provinces	71	36
Quebec	94	50
Ontario	120	103
Prairie Provinces	58	75
B.C./N.W.T	28	28
Total Canada	371	292

Note: The numbers in this table have been rounded.

Figure 6-8
End Use Demand For Refined Petroleum Products



The largest reductions occurred in the Atlantic Provinces, where capacity was reduced by 35 thousand cubic metres a day (approximately 50 percent) and in Quebec, where four Montreal refineries were closed representing 44 thousand cubic metres per day of capacity.

The major factor behind the refinery rationalization was the decrease in the demand for petroleum products. From 1980 to 1985, domestic demand for main products (motor gasoline, middle distillate and heavy fuel oil) fell by about 25 percent, which approximates the 21 percent decrease in Canadian refinery capacity during the period. Besides reductions in crude distillation capacity, several refineries were upgraded in response to changes in the demand for particular products, including the drop in the demand for heavy fuel oil and the increased use of unleaded gasoline. Refinery configurations were also altered as a result of changes in the availability and relative costs of different feedstocks.

For our analysis we have assumed that aggregate Canadian refinery capacity would remain unchanged and that it would continue to require a similar mix of feedstocks in the future as it now does.

To derive refinery feedstock requirements in each region of the country an assessment must be made of a number of important variables including refinery flexibility in manufacturing the various petroleum products, product yields, the necessity for inter-regional transfers of products, changes in inventory levels, refinery consumption, losses and/or gains during crude oil processing and projected levels of imports and exports of petroleum products.

Refinery Feedstock Requirements

Our projections of refinery feedstock requirements for the low and high price cases are shown in Table 6-7.

In the low price case, we project that the domestic demand for petroleum products will rise from 213 thousand cubic metres per day in 1985 to 258 thousand cubic metres per day in 2005 - an increase of about 20 per cent. In the high price case, the demand for petroleum products is projected to drop from 213 thousand cubic metres per day in 1985 to a low of 205 thousand cubic metres per day in 1995 after which demand rises so that by 2005 demand approximates the 1985 level.

Exports and imports of petroleum products play an important role in balancing supply and demand. In some cases, export sales are critical to the viability of independent marketers and of certain refineries that have an insufficient share of the domestic market to make their facilities viable. Product exports also allow refiners to balance their operations by exporting products produced jointly with other products required to meet domestic demand.

Exports of petroleum products were estimated on the basis of the first year's experience of operating in a deregulated environment. In 1985, total product exports amounted to 26 thousand cubic metres per day and we estimate that exports will continue at about the same level throughout the outlook period.

Imports are assumed to be made to satisfy the demand not able to be met from domestic refineries or from inter-regional transfers from adjacent regions of Canada. With the closing of a number of refineries in recent years, product imports have increased and we anticipate additional imports in the future. In 1985, 14 thousand cubic metres per day of petroleum products were imported and we see these rising to 53 thousand cubic metres per day by 2005 in the low price case. In the high price case, however, we see product imports rising to only 22 thousand cubic metres per day by 2005. Imports are likely to consist largely of motor gasoline, middle distillate and heavy fuel oil into eastern Canada. Should product imports increase to the levels indicated in the low price case, there is a possibility that new refinery capacity would be needed in the late 1990s. Any decision with respect to additional refinery capacity will have to be taken against the then prevailing and prospective conditions in oil markets.

Inventory levels by product and by region were established at essentially a constant number of days supply through the review period. In recent years, refiners have been carrying less inventory, resulting in lower operating costs and reduced seasonal inventory fluctuations. Inventories of petroleum products were reduced considerably in 1985 and we do not expect to see another such inventory adjustment during the review period.

In the low price case our projections indicate that Canada's total requirements for refinery feedstock will grow from 231 thousand cubic metres per day in 1985 to 250 thousand cubic metres per day by the year 2005 - an increase of 8 per cent. In the high price case, refinery feedstock requirements are projected to remain close to 1985 levels.

Our outlook for crude oil demand varies between eastern and western Canada. In eastern Canada, we expect crude runs will remain rela-

Table 6-7

Refinery Feedstock Requirements

(Thousands of Cubic Metres per Day)

Low Price Case

	1985	1990	1995	2000	2005
Demand for Petroleum Products	213	218	225	238	258
Product Exports	26	24	24	24	24
Product Imports	-14	-23	-29	-38	-53
Inventory Change	-17	1	2	3	0
Refinery Use,Loss and Other	23	17	18	18	21
Refinery Feedstock Requirements	231	237	240	245	250
Other Adjustments					
Partially Processed Oil and Other Material	-6	-6	-5	-5	-5
Gas Plant Butanes	-3	-3	-3	-3	-3
Domestic Requirements for Crude Oil	222	228	232	237	242

High Price Case

	1985	1990	1995	2000	2005
Demand for Petroleum Products	213	210	205	209	219
Product Exports	26	25	24	24	24
Product Imports	-14	-18	-16	-18	-22
Inventory Change	-17	-1	0	1	0
Refinery Use,Loss and Other	23	17	17	18	18
Refinery Feedstock Requirements	231	233	230	234	239
Other Adjustments					
Partially Processed Oil and Other Material	-6	-6	-4	-4	-4
Gas Plant Butanes	-3	-3	-3	-3	-3
Domestic Requirements for Crude Oil	222	224	223	227	232

Note: The numbers in this table have been rounded.

Source: Appendix Table A6-17

tively constant at 150 to 160 thousand cubic metres per day in both price cases throughout the review period and, as noted earlier, rising product demand is in part met by product imports.

Nominal refinery capacity in eastern Canada (Table 6-6) is greater than that likely to be available for the manufacture of petroleum products. For example, in Ontario, the technical refining capacity includes approximately 20 thousand cubic metres per day in the petrochemical industry. This capacity was built to process crude oil and equivalent for the manufacture of petrochemical feedstocks. Oil products are a by-product of the process and economics would not normally justify increased throughput in the petrochemical facilities in order to meet demand for fuels. As a result of the limited refining capacity, imports of petroleum products into eastern Canada are projected to be necessary as indicated previously.

In western Canada, crude runs are forecast to increase from 79 thousand cubic metres per day in 1985 to 90 thousand cubic metres per day in the low price case and to 84 thousand cubic metres per day in the high price case by the year 2005. Most of this increase in crude runs is likely to occur in the Edmonton refining complex as these refiners expand their supply orbits further into British Columbia.

Overall, changes in product requirements imply an increase in the utilization of distillation capacity from the 1984 level of about 79 percent to about 85 percent by the year 2005 which experience suggests is the maximum sustainable capacity. In the longer term we also expect that refineries will be modified in order to meet the demands posed by changes in the quality of petro-

Table 6-8

Light and Heavy Crude Oil Requirements

(Thousands of Cubic Metres per Day)

Low Price Case

	1985	1990	1995	2000	2005
Domestic Requirements for Crude Oil	222	228	232	237	242
Requirements for Domestic Heavy Crude Oil	15	18	17	18	19
Domestic Requirements for Light Crude Oil	207	210	215	219	223

High Price Case

	1985	1990	1995	2000	2005
Domestic Requirements for Crude Oil	222	224	223	227	231
Requirements for Domestic Heavy Crude Oil	15	18	17	18	19
Domestic Requirements for Light Crude Oil	207	206	206	209	212

Note: The numbers in this table have been rounded.

Source: Appendix Table A6-18

leum products and by shifts in the product demand mix.

Table 6-7 shows the implications of refinery feedstock requirements for Canada's total demand for crude oil. Canadian refineries can, at present, process only a limited amount of heavy crude oil; light crude oil is used for most of their feedstock requirements. It is important, therefore, to identify separately refinery requirements for both of these grades of crude oil (Table 6-8).

Domestic requirements for heavy crude oil produced in Canada are the same in both the low and high price cases because demand for domestic heavy crude oil is essentially asphalt related and the asphalt demand estimates in various regions of Canada do not vary appreciably under the two price scenarios. Canadian requirements for domestic heavy crude oil were determined using a ratio of 2.48 cubic metres of heavy crude to yield one cubic metre of asphalt. The projection also includes a continuing requirement of some five thousand cubic metres per day of indigenous heavy crude oil for the manufacture of refined products other than asphalt.

By the early 1990s domestic crude oil is unlikely to be moving east of Ontario under either the low or high price case. Hence, by 1995, we expect the Quebec market for domestic heavy crude oil to be unavailable.

The domestic demand for heavy crude oil is projected to rise slowly from about 15 thousand cubic metres per day in 1985 to 19 thousand cubic metres per day in 2005. By the end of the study period we see domestic heavy crude oil accounting for only 8 percent of the refinery crude oil diet in Canada. The reason for this low heavy crude oil demand in Canada, in contrast to the U.S., Japan and Europe, is that during the period of administered oil prices in Canada from the early 1970s to mid 1980s, Canadian refiners had little incentive to upgrade their facilities to use heavy crude oil. In the rest of the world, the differentials between light and heavy crude oil prices favoured investment in improved facilities. Canadian refiners did not see the need for such investment; they had first access to sufficient quantities of Canadian light crude oil and light/heavy crude price differentials in Canada did not support upgrading. These differentials have since narrowed further with the recent fall in oil prices, making refinery upgradings unattractive, possibly for some time to come.

6.9 Supply/Demand Balances

Canada currently produces about as much crude oil in total (light and heavy) as it consumes. However, production is not in balance with refinery feedstock requirements because Canadian refiners use primarily light crude oil to meet their demand for petroleum products but an increasing proportion of Canadian production consists of heavy crude oil. In order to assess the extent to which feedstock requirements can be met from domestic

production, it is necessary to examine separately the supply/demand balances for light and heavy crude oil.

6.9.1 *Light Crude Oil*

For light crude oil, domestic supply is now about equal to total domestic requirements. The economics of transportation are such that imported crude oil satisfies most of the requirements in the Atlantic provinces and about half that of Quebec; crude oil is exported from western Canada. Although producers and refiners have access to both domestic and foreign oil markets, we have assumed that domestic crude oil will be used to satisfy refinery demand first in the Prairie provinces and British Columbia followed, when sufficient crude oil is available, by that in Ontario and then Quebec. Excess supply or shortfalls of domestic crude oil are assumed to be taken up by exports or imports as the case may be.

Figure 6-9 illustrates the supply and demand balance for light crude oil and equivalent and Table 6-9 shows our estimates of the trade in light crude oil for the low and high price cases respectively. Our estimate of light crude supply includes synthetic oil production and the projected output from regional upgrading plants processing heavy crude oil and bitumen.

Based on prices levelling off at $ US 18 per barrel in the longer-term (our low price case) we estimate that the supply of light crude oil in Canada will fall sharply during the review period - from 204 thousand cubic metres a day in 1985 to about 81 thousand cubic metres a day in the year 2005. In the high price case, with prices reaching $ US 27 per barrel in the 1990s, we project that the supply of light crude oil will

Table 6-9

Light Crude Oil and Equivalent Supply and Demand Balance

(Thousands of Cubic Metres per Day)

Low Price Case

	1980	1985	1986	1990	1995	2000	2005
Domestic Supply [a]	209	204	204	162	122	100	81
Imports [b]							
-Atlantic/Quebec	69	43	48	48	71	72	73
-Ontario	0	0	0	0	22	47	69
Total Supply	278	247	252	210	215	219	223
Total Domestic Requirements	278	207	201	210	215	219	223
Excess Supply (Potential Exports)	0	40	51	0	0	0	0

High Price Case

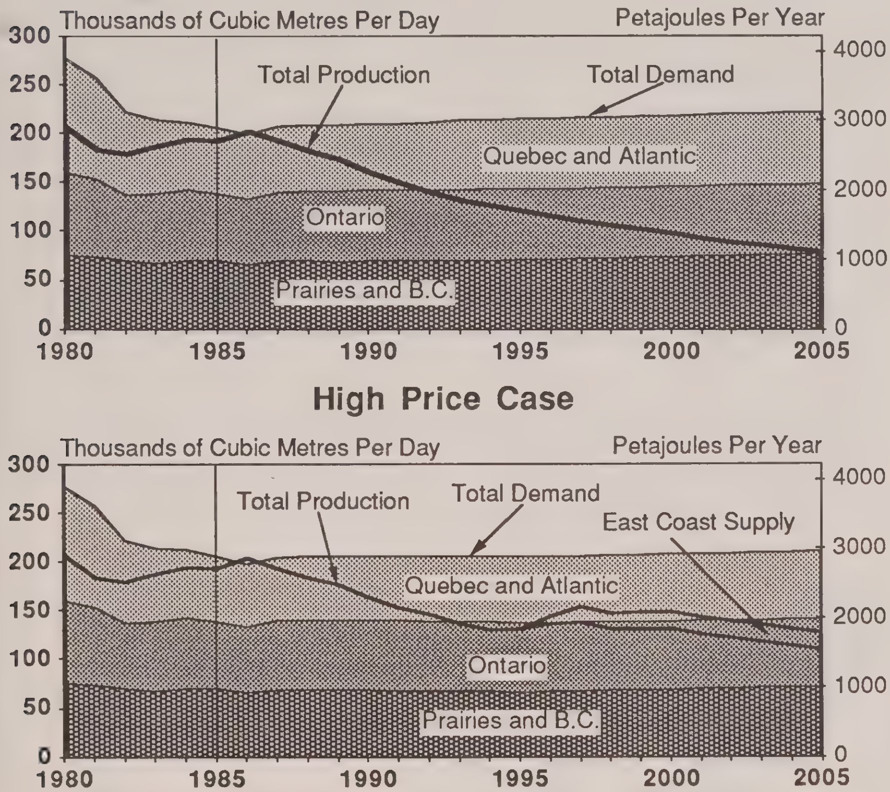
	1980	1985	1986	1990	1995	2000	2005
Domestic Supply[a]	209	204	205	165	132	150	128
Imports[b]							
-Atlantic/Quebec	69	43	47	48	65	52	52
-Ontario	0	0	0	0	9	7	32
Total Supply	278	247	252	213	206	209	212
Total Domestic Requirements	278	207	199	206	206	209	212
Excess Supply (Potential Exports)	0	40	53	7	0	0	0

Note: The numbers in this table have been rounded.

[a] Domestic supply excludes diluent requirements but includes upgraded heavy crude oil.
[b] In this analysis all imports are assumed to be in the light crude oil category, although some imports may consist of heavy crude oil.

Source: Appendix Tables A6-14 and A6-17

Figure 6-9
Supply and Demand - Light Crude Oil
Low Price Case



Source: Appendix Tables A6-14 and A6-17

decrease - but less dramatically - to approximately 128 thousand cubic metres per day in 2005.

We emphasize, however, that in the high price case this conclusion may be too conservative. The production of increased quantities of synthetic light crude oil from mining plants could be viable at $ US 27 and more upgrading capacity could be constructed than we have assumed to convert bitumen produced by the in situ process to light oil.

Figure 6-9 and Table 6-9 indicate that in total, demand for light crude oil is consistently above indigenous supply. Amounts available for export correspondingly decline. The decrease in the supply of light crude oil will likely cause delivery of Canadian light crude oil to Montreal refineries to cease and Ontario refiners will be faced with importing crude oil to meet at least part of their requirements in the 1990s in both the low and high price cases. Thus, imports are expected to rise from about 43 thousand cubic metres per day in 1985 to about 142 thousand cubic metres per day and 84 thousand cubic metres per day in 2005 in the low and high price cases respectively. These quantities represent 64 and 40 percent respectively of estimated total Canadian requirements of light crude oil and equivalent in 2005.

The circumstances surrounding imports of crude oil have changed fundamentally over the years. Beginning in the early 1960s, imported oil was progressively displaced by oil from western Canada and, by 1982, refineries in Quebec and the Atlantic provinces were using domestic crude oil to satisfy a substantial portion of their requirements. This increased use of domestic crude oil by Canadian refineries was consistently encouraged by government policy and in 1982 the federal government began subsidizing the transportation of western Canadian crude oil to the Atlantic region. However, with the introduction of the Western Accord on 1 June 1985, this transportation subsidy was terminated. Consequently, foreign crude oil once again supplied virtually all of the feedstock requirements in Atlantic Canada.

The Quebec market is now served by crude oil from both foreign and domestic sources. To be marketable in Montreal, western Canadian oil must be competitive with offshore crude oil. Over time, Quebec will make increasing use of offshore feedstocks.

Although for this study we have assumed that domestic crude oil will be used first to satisfy Canadian demand, in fact in a deregulated market environment, crude oil producers may export in preference to selling their oil in Canada.

We are assuming that there will be sufficient crude oil available from foreign sources to meet Canadian demand for imports. If sufficient light crude oil were not available one would expect a widening of price differentials between light and heavy crude, perhaps providing an

incentive for Canadian refiners to make the necessary investments to use more heavy crude oil. It is also possible that more synthetic light crude could be produced by upgrading bitumen.

6.9.2 Heavy Crude Oil

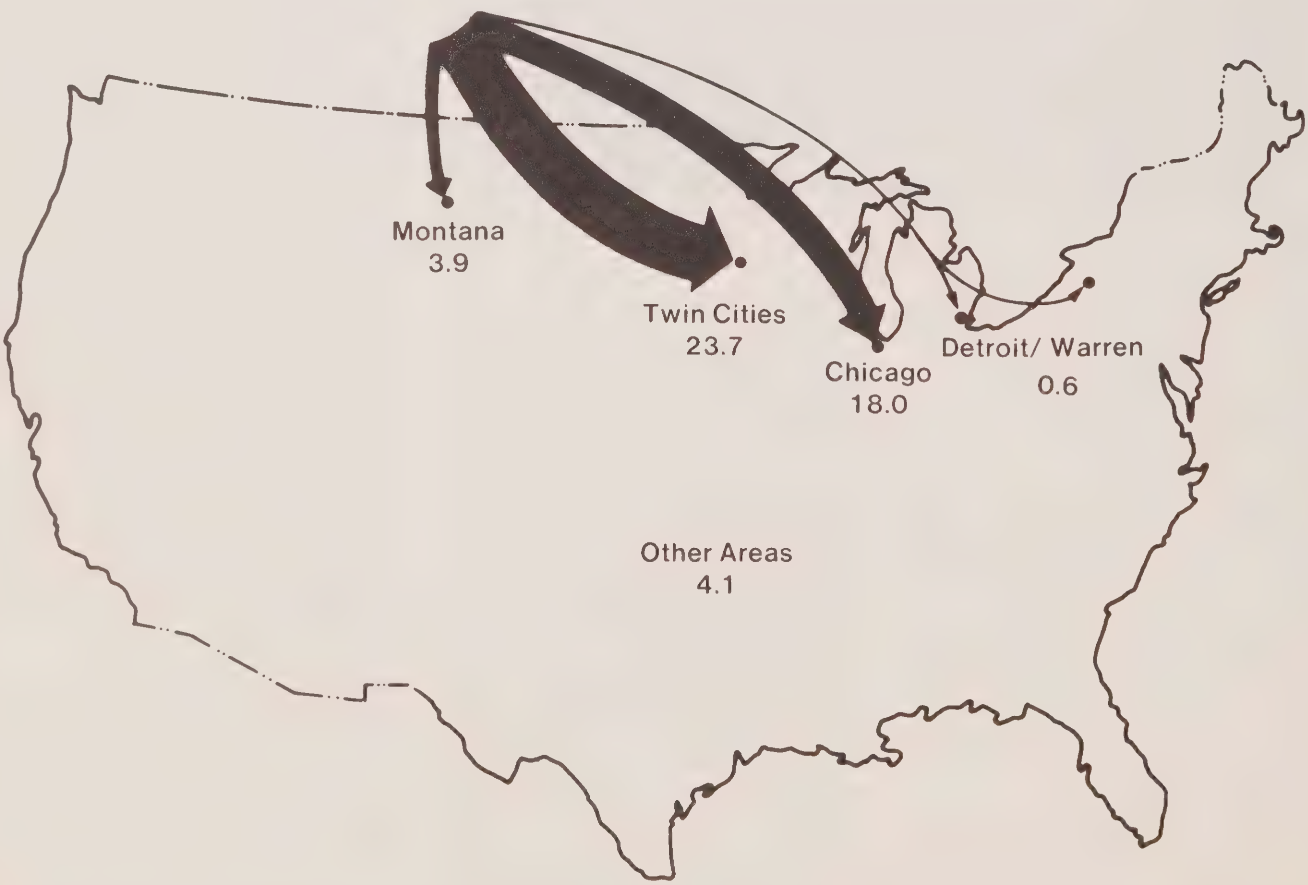
The strong growth of heavy crude oil production in recent years has resulted in substantially increased exports to U.S. markets. These have more than doubled from the levels of under 20 thousand cubic metres per day which prevailed in the period 1975 to 1981. Figure 6-10 illustrates the major locations in the northern tier of the United States to which Canadian heavy crude oil is exported.

The surge in export volumes is attributable to the increased ability of refiners in the United States to process more heavy crude oil and the increased availability of heavy crude oil in Canada which resulted from the high prices prevailing since 1979.

Northern tier U.S. markets will continue to be the major users of Canadian heavy crude oil. Currently, they receive some 50 thousand cubic metres a day and have the potential to import up to 80 thousand cubic metres a day of Canadian heavy crude oil. Whether this level

Figure 6-10

Exports of Heavy Crude Oil by Market
1st Half 1986
(Thousands of Cubic Metres per Day)



is attained depends on whether Canadian heavy crude continues to be priced competitively with similar accessible feedstocks, both United States domestic and offshore crude oils, and on the availability of pipeline capacity in Canada.

In the high price case, our projected availability of indigenous heavy crude oil for export exceeds the current absorptive capacity of the northern tier market in the latter part of the study period. Potential exists, however, for additional volumes to be used in the Wood River, Illinois refining area which has a heavy crude oil capacity of about 15 thousand cubic metres per day. Some potential exists in the Anacortes, Washington area for sales of heavy crude oils of the Cold Lake type, the only heavy crude which has access to the Trans Mountain pipeline. However, in this market Canadian crude oil must be heavily discounted to compete against Alaskan North Slope oil, which cannot be exported from the United States and thus presents formidable competition.

Beyond markets accessible by pipeline, some countries in the Pacific Rim, notably Japan and South Korea, could provide an outlet for Cold Lake type crude oils if competitively priced. The U.S. Gulf coast is also a potential market. Small amounts of heavy crude oil were successfully shipped to a Far East destination and to U.S. Gulf coast destinations in the past year demonstrating the capability of the transportation systems. Canadian heavy crude oil will, however, be at a disadvantage owing to high transportation costs and the highly competitive nature of these markets.

Table 6-10 summarizes our projections of the supply and demand for heavy crude oil. In the low price case we estimate that the supply of heavy crude oil will decrease from 55 thousand cubic metres per day in 1985 to about 41 thousand cubic metres per day in 2005.

Table 6-10 indicates that, in the low price case, there is a projected excess supply (potential exports) of heavy crude oil throughout the study period but the excess supply drops from 40 thousand cubic metres per day in 1985 to 22 thousand cubic metres per day in 2005. In this case we see no difficulty in the marketing of Canadian heavy crude oil as existing markets are likely to be able to absorb projected volumes.

In the high price case the supply of heavy crude oil increases from 55 thousand cubic metres per day in 1985 to 114 thousand cubic metres per day by 2005. This supply projection is net of the heavy crude oil required as feedstock for upgraders.

As in the low price case, Table 6-10 suggests that there will continue to be an excess supply of heavy crude oil available for export throughout the forecast period. The excess supply increases, in the high price case, from 40 thousand cubic metres per day in 1985 to 95 thousand cubic metres per day in 2005. By the mid-1990s, we see the excess supply about equalling the capacity of the United States north-

Table 6-10

Heavy Crude Oil
Supply and Demand Balance

(Thousands of cubic metres per day)

Low Price Case

	1985	1986	1990	1995	2000	2005
Domestic Supply [a]	55	64	50	47	43	41
Domestic Requirements	15	16	18	17	18	19
Excess Supply (Potential Exports)	40	48	32	30	25	22

High Price Case

	1985	1986	1990	1995	2000	2005
Domestic Supply [a]	55	65	73	94	94	114
Domestic Requirements	15	16	18	17	18	19
Excess Supply (Potential Exports)	40	49	55	77	76	95

Note: The numbers in this table have been rounded.

[a] Domestic supply includes diluent but excludes heavy crude oil used in regional upgraders.

Source: Appendix Table A6-18

ern tier market to absorb Canadian heavy crude oil. Thus, by 2005, either new export markets or increased heavy crude processing capacity in Canada will be needed if production potential is to be achieved. Such increased heavy crude processing capacity could be either in the form of increased use by refineries or larger upgrading capacity than we assumed.

6.10 Concluding Comments - Implications for Oil Pipelines

We conclude this chapter with a brief description of the major crude oil pipeline systems in Canada followed by a discussion of the impact that our projected crude oil supply/demand balances could have on their operation.

Trans Mountain Pipe Line Company Limited and Interprovincial Pipe Line Limited operate the two major pipeline systems through which Canadian crude oil is moved to domestic and export markets. In addition, the Portland-Montreal pipeline plays an important role in satisfying Montreal refineries' offshore crude oil requirements. The locations of these pipelines are shown on Figure 6-11.

Trans Mountain operates a pipeline for the shipment of crude oil and refined petroleum products from receipt points in Alberta and British Columbia to delivery locations in British Columbia, principally the four refineries located in the Vancouver area. The Westridge marine terminal in Vancouver has been used from time to time to export domestic crude to offshore markets or, when required, to ship crude to refineries in eastern Canada. Trans Mountain also operates a lateral from Sumas, B.C. to Anacortes, Washington where four refineries are located. While these U.S. refiners' crude diet is almost exclusively Alaskan North Slope crude, they do take Canadian crude when it is priced competitively. Though Trans Mountain is used primarily to ship crude from Edmonton to Vancouver, regular shipments of refined petroleum products (gasoline and diesel) from Edmonton to Kamloops, B.C. commenced during 1985.

On average, during 1985, Trans Mountain shipped 25 thousand cubic metres per day of crude oil and products of which 21 thousand cubic metres per day was shipped to domestic locations and 4 thousand cubic metres per day was transported to export destinations in Washington or for delivery via tanker to offshore markets. Trans Mountain's sustainable capacity is approximately 30 thousand cubic metres per day.

For both price cases we expect that Trans Mountain will continue to ship domestic light crude oil to Vancouver in order to satisfy the crude requirements there. We expect that the movement of petroleum products on Trans Mountain, which began in 1985, will continue and increase in the years to come. Although both price cases project continued potential exports of light crude for the next few years, we do not expect large volumes to be moved to export markets via Trans Mountain in view of the price discounting that generally must take place for domestic crude oil to compete against Alaskan North Slope crude oil.

Interprovincial operates the largest and most important crude oil pipeline system in Canada stretching over 3 700 kilometres from Edmonton, Alberta to Montreal, Quebec. The pipeline system may, at any time, be moving 35 different grades of petroleum including refined petroleum products, natural gas liquids and light and heavy crude oils on behalf of about the same number of shippers.

Interprovincial transports these to locations in the Prairie provinces; and to refining centres in Sarnia, Toronto and Nanticoke, Ontario; Montreal, Quebec; the Minneapolis-St. Paul area of Minnesota; Superior, Wisconsin; the Chicago area of Illinois and Indiana; Detroit, Michigan; Toledo and Canton, Ohio; and the Buffalo, New York area.

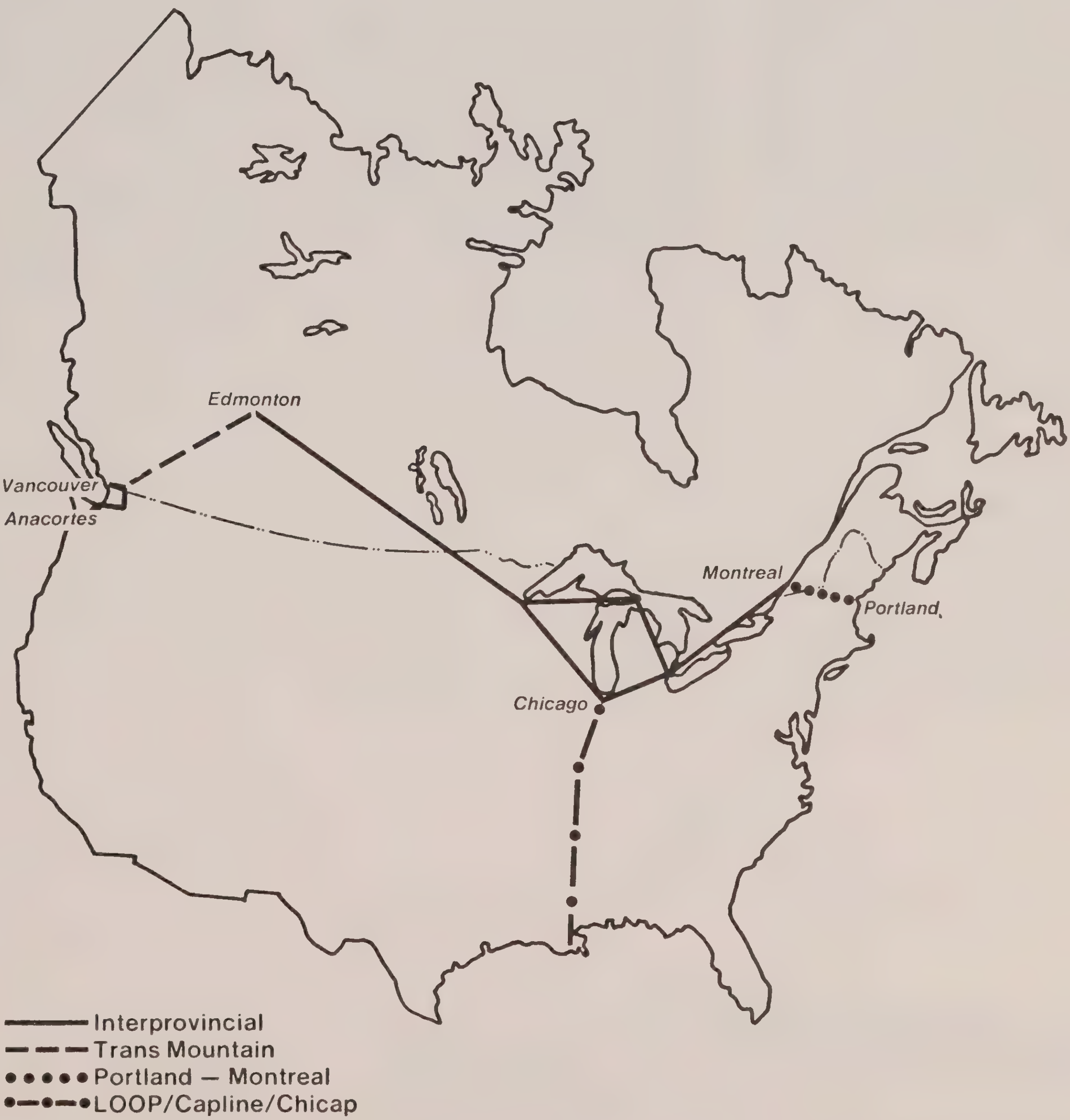
During 1985 throughput on the system averaged about 208 thousand cubic metres per day with deliveries of 142 and 66 thousand cubic metres per day to domestic and export locations respectively. Since late 1984, the company has generally not had sufficient capacity to move all volumes tendered by shippers. To remove this capacity constraint, the company has embarked on a major, three phase, expansion program that, when completed by the end of 1987, will add approximately 40 thousand cubic metres per day of capacity to the system.

The major concern for the Interprovincial pipeline system in recent years has been the lack of capacity to handle tendered volumes. On the basis of estimated supply for both price cases lack of capacity is not likely to be a problem in the future as the supply of light crude oil declines to the point where, in the early 1990s, crude deliveries to Montreal would have to cease, as shown on Figure 6-9.

A major issue could be how to deliver imported crude oil into Ontario. In both price cases, increasing imports of crude oil are projected to be

Figure 6 - 11

Major Crude Oil Pipelines



necessary to satisfy Ontario's requirements (Table 6-10). Imports of crude to Ontario could be achieved by increased throughput on the Portland-Montreal system (discussed below) in conjunction with the reversal of the Interprovincial Sarnia-Montreal pipeline. Alternatively, foreign crude might be shipped through the U.S. pipeline system from the Louisiana Offshore Oil Port (LOOP) in the Gulf of Mexico to Chicago (via the Capline and Chicap pipelines) and then to Ontario on the Lakehead portion of the Interprovincial system.

The Portland-Montreal pipeline system transports crude oil from South Portland, Maine to Montreal over a distance of 380 kilometres and is the primary means of delivering foreign crude to Montreal refiners. The present capacity of the pipeline and the two remaining refineries in Montreal are virtually the same at 30 thousand cubic metres a day. In recent years Portland-Montreal has operated below its capacity because Montreal refineries satisfied most of their requirements with domestic crude oil delivered by Interprovincial.

In both price cases the Portland-Montreal pipeline will become increasingly important to supply Montreal refiners' crude requirements. As domestic light crude producibility declines, domestic crude deliveries to Montreal will be reduced and imports via Portland-Montreal will likely increase. To the extent that Ontario refiners import crude through a reversed Sarnia-Montreal pipeline, additional capacity will be needed on the Portland-Montreal system. Deliveries to Montreal could be increased to about 60 thousand cubic metres a day by the reconnection of pumps on the larger of the system's two pipelines to support imports to Ontario.

Chapter 7
Natural Gas Liquids

Natural gas liquids (NGL), which consist of ethane, propane, butanes and pentanes plus, are by-products of the processing of natural gas and the refining of crude oil. The supply of NGL from natural gas depends upon gas processing plant design, the composition of the gas and the volume of gas processed. The supply of NGL from crude oil refining is related to refinery configuration, the quality of the crude oil and the volume of crude oil refined.

These factors are discussed in this chapter with reference to supply from gas processing and main transmission line reprocessing (straddle) plants, refineries, synthetic crude oil and upgrading plants, and frontier areas. In addition, supply/demand balances are shown for each of ethane, propane and butanes. The pentanes plus supply/-demand balance is part of the overall supply/demand balance for light crude oil and is discussed in Chapter 6.

Historical production of NGL is shown in Appendix Table A7-1 and projected production in Appendix Table A7-2.

7.1 Gas Plants

The low and high price cases for NGL production from natural gas processing and reprocessing plants in the conventional areas are based on the respective projections of natural gas production and on assumptions about NGL yields (recovery of NGL per unit of natural gas production).

In the 1960s, yields of propane, butanes and pentanes plus increased in conjunction with increases in the production and processing of solution gas and with the implementation of large gas cycling schemes; both of these sources were rich in NGL. However, by the mid-1970s the yields of these liquids, most notably pentanes plus, had begun to decline as a result of the declining liquid content of the gas stream.

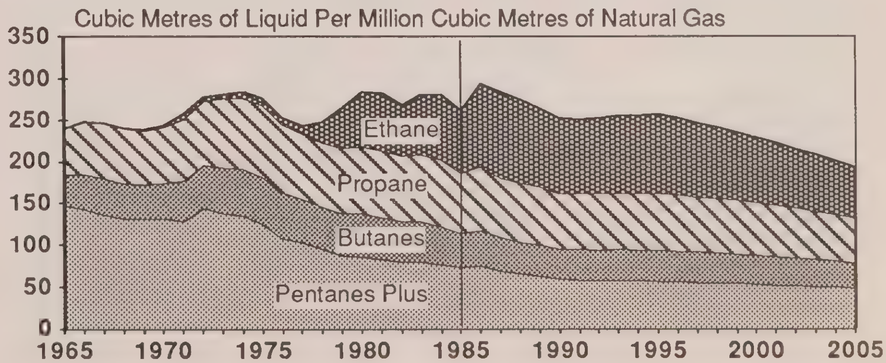
The production of solution gas and gas from cycling schemes is expected to continue to decline in the future and drier non-associated gas to comprise an increasing share of natural gas production. Thus the trend to lower yields of these liquids is projected to continue throughout the forecast period. Historical and projected yields are shown for each NGL component in Figure 7-1. The figure shows yields for the low oil price case but those for the high price case are very similar.

Though the yields of propane, butanes and pentanes plus were already declining in the late 1970s the extraction of ethane was just beginning. The yield of ethane has continued to increase as extraction facilities have been added and expanded at reprocessing plants, and more recently as a result of the addition of extraction facilities at field gas plants to meet the demand for liquids for enhanced oil recovery. Although the ethane component of future gas streams may be somewhat lower than in the past, increased throughputs at plants extracting ethane during the next few years could increase the ethane yield. In the longer term reduced throughputs at these plants will lower the yield.

Production of NGL from gas plants is directly related to the volume of natural gas produced and processed. Because our projections of natural gas production do not take account of any potential exports beyond those authorized at present, production of both natural gas and the associated liquids peaks in 1989. In the high price case, were natural gas production to more closely approximate productive capacity, NGL production would be correspondingly higher.

As can be seen in Figures 7-2, 7-4 and 7-6, NGL production falls off after 1989 in the low price case as natural gas production declines. In the high price case NGL production declines from 1990 to 2000 as currently authorized exports decline, after which increases in natural gas production to meet domestic

Figure 7-1
NGL Yields
Low Price Case



demand result in corresponding increases in NGL production until 2003. After 2003, with natural gas production again declining because it can no longer meet demand, NGL production declines.

The differences in the NGL production profile between the two price cases become quite marked by 2005 (Table 7-1). This is a direct result of the difference in the natural gas supply projections; in 2005 the production of gas is about fifty percent greater in the high price case than in the low.

Detailed plant by plant projections of production for each natural gas liquid are provided for the low price case and summary tables are provided for the high price case in Appendix Tables A7-3 to A7-6.

Most producing natural gas pools are fully developed and are on decline so that the price differential between our two cases has a negligible effect on the economics of production. Therefore, the projections of production from existing field plants and currently producing pools are assumed to be the same in both the low and high price cases. Projections of straddle plant production and production from uncommitted reserves and reserves additions are different in the two cases reflecting differences in natural gas production.

7.2 Oil Refineries

Our projections of propane and butanes supply from refineries are based on the low and high price case projections of crude oil feedstock requirements discussed in Chapter 6. Although it is recognized that throughout the projection horizon the quality of crude oil refined in Canada may change, and that refinery configurations may have to be altered to meet changing product demands, our projections do not take any such changes into account. NGL production per unit of crude oil throughput is assumed to remain about the same, on a regional basis, throughout the forecast period.

As shown in Table 7-1, refinery propane and butanes production increases only moderately over the study period, for both price cases. Production in the low price case increases ten percent from 1985 to 2005 compared to four percent in the high price case, reflecting the higher demand for refinery feedstocks in the former.

The projections of propane and butanes supply from refineries are shown by region in Appendix Tables A7-7 and A7-8 respectively for each of the low and high price cases.

Table 7-1
Supply of Natural Gas Liquids

(Thousands of Cubic Metres per Day)

	1985	1995		2005	
		Low Price Case	High Price Case	Low Price Case	High Price Case
Gas Plants					
Ethane	17.5	23.6	22.4	8.6	13.6
Propane	16.9	16.6	15.4	7.5	12.3
Butanes	9.7	9.1	8.4	4.3	6.9
Pentanes Plus	17.2	14.0	13.1	6.8	10.8
Refineries					
Ethane	–	–	–	–	–
Propane	3.0	3.2	3.0	3.3	3.1
Butanes	2.2	2.3	2.2	2.4	2.3
Pentanes Plus	–	–	–	–	–
Total					
Ethane	17.5	23.6	22.4	8.6	13.6
Propane	19.9	19.8	18.4	10.8	15.4
Butanes	11.9	11.4	10.6	6.7	9.2
Pentanes Plus	17.2	14.0	13.1	6.8	10.8

Note: The numbers in this table have been rounded.

Source: Appendix Table A7-2

7.3 Synthetic Crude Oil and Upgrading Plants

Our supply projections do not include any production of NGL from synthetic crude oil plants or heavy crude oil upgraders. Current indications are that the recovery of NGL from the gases produced and used for fuel would provide little or no economic benefit.

7.4 Frontier Areas

As with gas supplies in western Canada, the liquids content of gas from the various frontier sources varies significantly. Arctic Islands gas, for example, is very dry while Scotian Shelf gas and some gas streams in the Mackenzie Delta and Beaufort Sea area have a substantial liquid content. In the event that frontier gas moves through Alberta it is likely to be stripped of liquids in one of the straddle plants in the province.

Frontier operations are not considered as firm supply in either the low or high price case and consequently no NGL production is projected from these areas.

7.5 Supply/Demand Balances

Supply/demand balances for ethane, propane and butanes are provided, by year, in Appendix Tables A7-10 to A7-12.

Since the mid-1970s production of NGL has been substantially in excess of domestic requirements and substantial quantities have been exported. Our projections (Figures 7-2 to 7-7) suggest that there will continue to be substantial but declining quantities of propanes and butanes available for export throughout much, if not all, of the outlook period.

For ethane in the low price case (Figure 7-2), near term increases in production are expected to be sufficient to meet a sharp increase in demand for miscible fluids, ethane being the preferred liquid for enhanced oil recovery in most reservoirs. The requirements for ethane in miscible floods (after allowing for reproduced quantities) are projected to increase in the near-term but decline to zero by 1997 in the low price case and by 2001 in the high price case. Ethane currently accounts for about 45 percent of the NGL volumes used in miscible floods; its share is projected to grow to 70 percent by 1990. These requirements are based on existing miscible enhanced oil recovery projects and on our projections of reserves additions in Appendix Table A6-6. The ethane requirements in the high price case exceed those of the low price case because of the higher demand for use in miscible floods in the 1985 to 1990 period.

In the longer term ethane demand is dominated by petrochemical requirements. For the high price case (see Figure 7-3), in 1995, supply and demand are shown to be in balance whereas supply exceeds demand in the low price case, as a result of lower demand for miscible fluids. Demand is projected to exceed supply in 1999 for the low price case and 1996 for the high price case.

Although surpluses of ethane are shown in some years, exports of ethane are not likely to occur in the future because of the closing of Columbia SNG Corporation's synthetic natural gas plant at Green Springs, Ohio, the sole customer for exported ethane in the past. Any production exceeding demand will probably be reinjected into the gas stream and sold as natural gas.

In the low price case propane demand (see Figure 7-4) is expected to increase in all sectors, but particularly for petrochemical, residential and commercial use. Petrochemical demand is projected to increase from the 1985 level of

Figure 7-2
Ethane Supply and Demand
Low Price Case

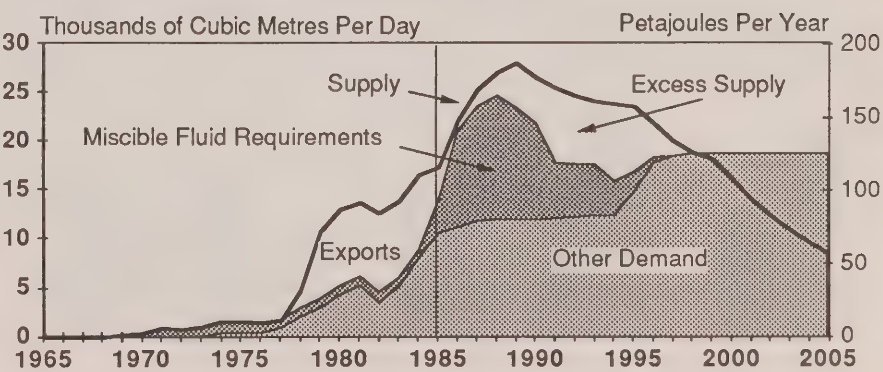
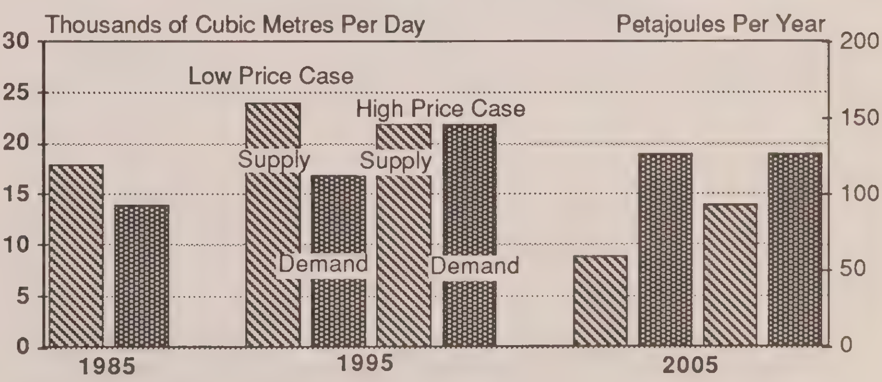


Figure 7-3
Ethane Supply and Demand
Comparison of Low and High Price Cases



Source: Appendix Table A7-10

Figure 7-4
Propane Supply and Demand
Low Price Case

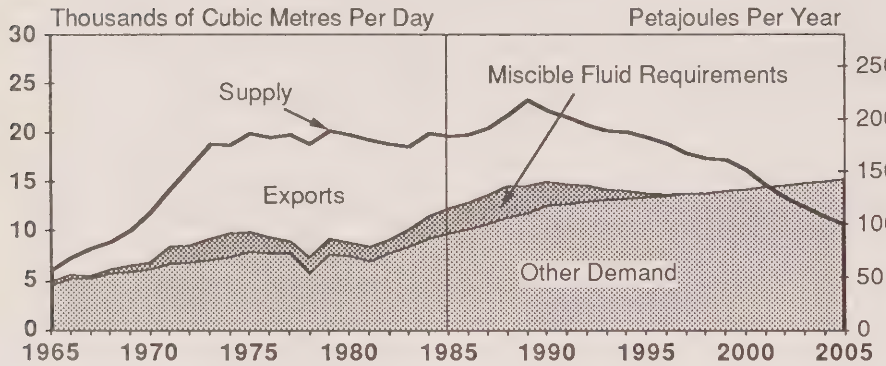
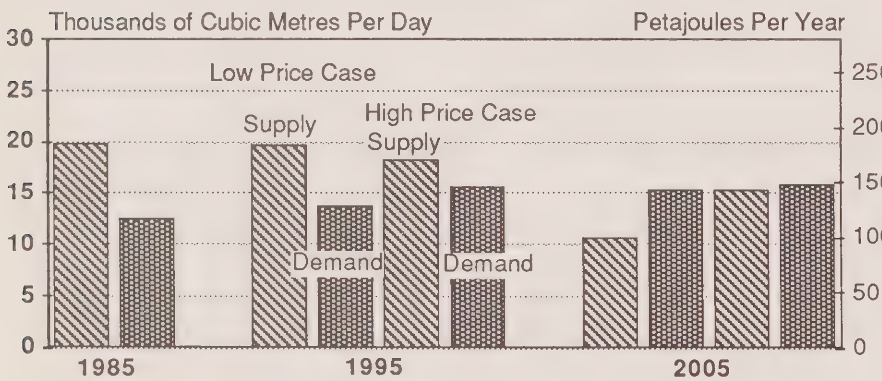
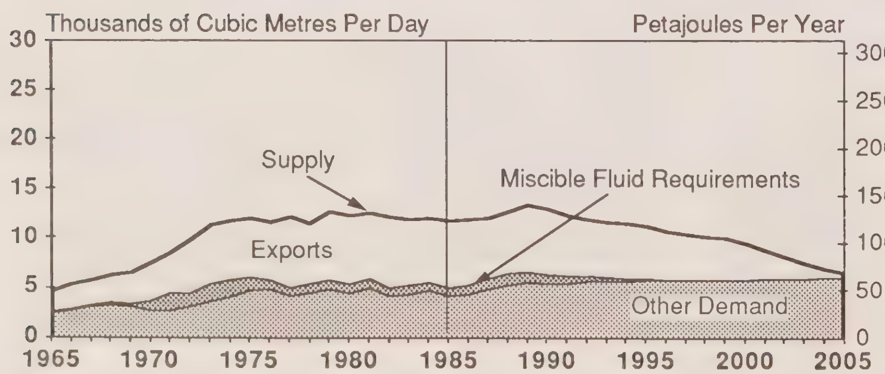


Figure 7-5
Propane Supply and Demand
Comparison of Low and High Price Cases



Source: Appendix Table A7-11

Figure 7-6
Butanes Supply and Demand
Low Price Case



1.7 thousand cubic metres per day in 1985 to 3.9 thousand cubic metres in 2005, and the residential and commercial demand from 5.4 to 7.3 thousand cubic metres per day over the same period. Requirements for propane in miscible floods (net of reproduced quantities) increase in the near term, but fall to zero as enhanced oil recovery requirements decline. The proportion of propane used in miscible floods, 33 percent in 1985, is projected to fall to about half that level by 1990. Total domestic demand is less than supply until 2002.

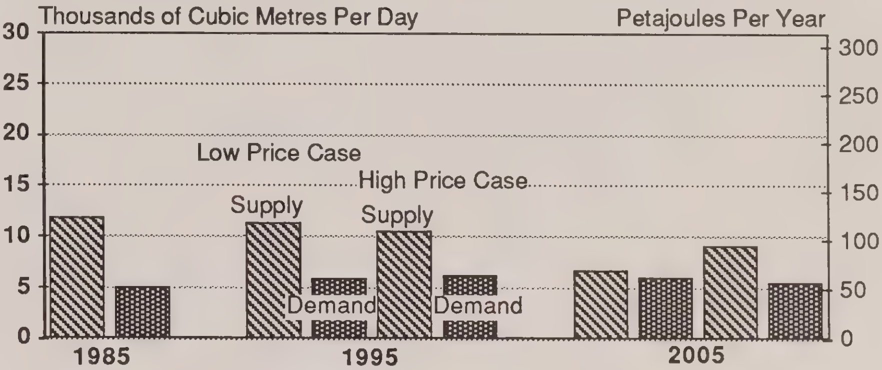
In the high price case slightly larger increases in demand occur as a result of greater propane use in transportation (Figure 7-5). Propane demand for miscible floods is higher than in the low price case as a result of higher crude oil reserves additions attributed to miscible floods.

Demand for butanes in the petrochemical sector is projected to grow from 1.1 thousand cubic metres per day in 1985 to 2.5 thousand cubic metres per day by 2005 in both price cases. The demand for butanes in the category entitled "other" on Figure 7-6 includes butanes for refinery feedstocks (gasoline blending) and end use. In the low price case demand for blending increases from 2.9 to 3.4 thousand cubic metres per day from 1985 to the end of the projection period and in the high price case remains essentially constant throughout the period. The differences between the low and high price cases (Figure 7-7) reflect the lower projections of gasoline demand in the high price case. The demand for butanes as a miscible fluid is projected to increase moderately in the short term and, as with

the other gas liquids, declines to zero by 1997 and 2001 in the low and high price cases, respectively. Butanes used in miscible floods are assumed to be almost entirely entrained in NGL mixes as opposed to being used on their own . Butanes supply is projected to exceed demand in both the low and high price cases throughout the outlook period.

Figure 7-7

Butanes Supply and Demand
Comparison of Low and High Price Cases



Source: Appendix Table 7-12

Chapter 8
Coal

In this chapter we examine the extent to which coal will contribute to the supply and demand for energy in Canada. The chapter begins with a description of the various types of coal and their utilization. This is followed by sections on resources and reserves, production, imports and exports and finally supply/demand balances.

Coals are classified according to their carbon content and their calorific value. The classes, ranging from lowest to highest heating value, are lignitic, subbituminous, bituminous and anthracitic. Lignitic and subbituminous coals are currently used mainly for thermal power generation but some deposits would also provide suitable feedstocks for coal gasification or liquefaction plants were such plants to prove economically viable. Bituminous coals can be used for thermal power generation or for coking in metallurgical industries; anthracitic coals can be used for domestic heating and for special applications such as titanium smelting. They can also be blended with bituminous coals to improve coking quality.

For the first half of this century, coal was the major source of energy in Canada; its importance diminished in the 1950s and 1960s due to the increasing use of oil and natural gas. Interest in Canadian coal began to revive in the late 1960s and the rapid escalation of world oil prices after 1973 enhanced the competitive position of the Canadian coal industry; western coal began to be used in Ontario, displacing some imports of U.S. coal and exports expanded. Canada became a net exporter of coal for the first time in 1981. The development of new markets has allowed the production of coal to increase every year since 1969 so that, by 1985, coal accounted for 15 percent of Canada's primary energy production. Canada has a large resource potential capable of contributing to further increases in production levels.

8.1 Resources and Reserves

Because the National Energy Board does not independently assess resources and reserves of coal, data from external sources were adopted for this report. Data on coal resources, compiled by the Geological Survey of Canada from its own and provincial sources, are shown in Appendix Table A8-2. Estimates of recoverable reserves are summarized by province and class in Table 8-1.

Coal resources are divided into two main categories depending on whether they are of immediate or future interest. To be of immediate interest resources must consist of coal seams with combinations of thickness, quality, depth and location which render them attractive for early exploration or development.

Resources of immediate interest are estimated to be 145 gigatonnes (3 500 exajoules) and those of future interest 1 800 gigatonnes (43 000 exajoules). These two categories are further subdivided into measured, indicated and inferred resources which denote decreasing levels of confidence in the estimates. Resources of future interest are almost all inferred whereas more than 50 percent of the resources of immediate interest are measured and indicated.

Recoverable coal reserves consist of that part of measured and indicated resources of immediate interest that are considered to be, with reasonable certainty, recoverable. For deposits to qualify as reserves, amongst other criteria, feasibility studies must have been done, specific plans for mining method and processing adopted and the

Table 8-1

Recoverable Reserves of Coal by Province and Class

Province	Class	Megatonnes	Petajoules
British Columbia	Lignitic	566	8 688
	Bituminous	2 098	61 471
Alberta	Subbituminous	918	18 140
	Bituminous	526	15 412
Saskatchewan	Lignitic	1 697	26 049
New Brunswick	Bituminous	18	527
Nova Scotia	Bituminous	445	13 039
Canada - Totals	Lignitic	2 263	34 737
	Subbituminous	918	18 140
	Bituminous	3 087	90 449
	Total	6 268	143 326

Note: The numbers in this table have been rounded.

Source: Coal Mining in Canada: 1983, Canmet Report 83-20E.

overall economic feasibility for development appear favourable. Coal reserves are therefore only a small portion of the total resource.

Of the reserves of coal, some are more desirable than others due to characteristics such as sulphur content. The increasing awareness of the dangers of air pollution has put a premium value on western coals which have generally less than one percent sulphur; eastern coals can contain as much as ten percent.

Total recoverable reserves (see Table 8-1) are 6 268 megatonnes (150 exajoules) which is about 100 times Canada's annual coal production. Of these reserves almost two-thirds are located in British Columbia and Alberta and almost 90 percent are estimated to be recoverable by surface mining methods.

8.2 Production

As shown in Appendix Table A8-1, annual coal production has increased continuously since 1969. Bituminous coal production increased by over 40 percent from 1983 to 1984 as five new mines came on production in late 1983. Of these, four were in British Columbia and one in Alberta. In 1985 there were 29 mines operating in Canada which produced 61 megatonnes of coal. Coal production in 1985 is summarized by province and class in Table 8-2. More than 95 percent of 1985 production was extracted from mines using surface mining methods. Bituminous coals represented 56 percent of the total production while subbituminous and lignitic coals accounted for 28 and 16 percent, respectively. All subbituminous and lignitic coals plus nearly 30 percent of the bituminous coals were used for thermal purposes; this amounted to 37 megatonnes or 60 percent of production.

In 1985, Alberta produced 25 megatonnes of coal or 41 percent of total production in Canada. Coal production in British Columbia totalled 23 megatonnes while Saskatchewan produced 10 megatonnes. Production in the Atlantic provinces was 3.4 megatonnes, six percent of total Canadian output.

The expansion in coal production can be attributed to a growing domestic market for thermal coal and increases in demand worldwide which led to increases in coal exports. The Canadian coal industry especially benefited from industrial expansion in Japan and Korea, which led to substantial exports of metallurgical coal, and from escalation of world oil prices, which led to increased exports of thermal coal. However, increases in world oil prices also had a negative effect on coal demand as energy conservation measures led to a lower than anticipated demand for steel which in turn reduced the demand for metallurgical coal. Because plastics and ceramics are replacing iron and steel in many applications, the demand for metallurgical coal may not increase as rapidly as once thought. The recent drop in oil prices dampens growth in demand for thermal coals but may not reduce coal demand below current levels; thermal coal is generally still competitive with oil based electricity generation under our two price scenarios.

Our projection of future production levels is based on the domestic demand forecast and on estimated exports. Figure 8-1 shows that coal

Table 8-2

Coal Production by Province and Class in 1985

Province	Class	Megatonnes	Petajoules	Percentage of Total Production
Nova Scotia	Bituminous	2.8	82.0	5
New Brunswick	Bituminous	0.6	16.4	1
Saskatchewan	Lignite	9.7	148.5	16
Alberta	Bituminous	7.8	229.7	13
	Subbituminous	16.9	333.4	28
	Subtotal	24.7	563.1	41
British Columbia	Bituminous	23.1	677.1	38
Canada	Bituminous	34.3	1 005.2	56
	Subbituminous	16.9	333.4	28
	Lignite	9.7	148.5	16
	Total	60.9	1 487.1	100
Canada	Thermal	36.5	n.a.	60
	Metallurgical	24.4	n.a.	40

n.a. not available

Note: The numbers in this table have been rounded.

Source: Statistics Canada, cat. no. 45-002.

production is expected to remain constant until the early 1990s in both the high and the low price cases after which it increases from about 60 million tonnes per year to about 100 million tonnes per year in 2005. There are however major uncertainties about export prospects and about domestic demand.

Electricity generation requirements in the Atlantic region and in Ontario, Saskatchewan and Alberta account for 78 percent of primary demand (see Chapter 4). In 2005 there is only a five percent difference between our two cases in domestic demand for coal, due to offsetting changes in Ontario and Alberta. Ontario's requirements for electricity generation are higher in the low oil price case; economic growth and electricity demand are higher in the low oil price case. The reverse is true for Alberta, and the changes in the two provinces' demand are almost equal.

Major uncertainties relating to domestic demands for coal are related to uncertainties about Ontario Hydro's expansion plans and to environmental concerns and legislation of emission standards. As discussed in Chapter 4, Ontario's requirements for coal for electricity generation are assumed to decline over the medium term, as new nuclear capacity (now under construction) replaces existing thermal generation. However, Ontario Hydro has no publicly stated expansion plans for the 1995-2005 period when, based on our projections, additional generation capacity will be required. We have assumed that coal is used to generate the additional electricity. Ontario Hydro's decision could be affected if growing concern over acid rain and its sources were to lead to adoption of stricter sulphur dioxide emission standards. Stricter emission standards could be met either by installing pollution reduction processes in coal burning plants or by burning low-sulphur coal. Both of these options mean that generation cost per kilowatt hour will be greater than that implied by today's relatively low prices for medium sulphur coal. Should Ontario Hydro choose to construct additional nuclear facilities our projections could be high, perhaps by as much as 19 megatonnes in the low price case and 15 megatonnes in the high price case in the year 2005.

8.3 Exports and Imports

Before 1970 Canadian coal exports were relatively small but this changed when increased demand for coking coal in Japan led to large export contracts with that country and the construction of a new coal terminal in Vancouver. In 1970 exports tripled to four megatonnes and continued to grow as export markets expanded, reaching 17 megatonnes in 1983 (see Appendix Table A8-3). In 1984 exports expanded further by 50 percent to meet new export contracts serviced from new mines in Alberta and northeastern British Columbia. These exports were facilitated by the construction of a new railroad in northern British Columbia. In 1985 exports reached 27 megatonnes. These exports were 82 percent metallurgical coal; Japan was the largest customer with 68 percent of all exports. Table 8-3 shows a summary of exports by province.

The coal industry world-wide has experienced large capacity increases in recent years which, combined with a stabilization in world demand for metallurgical coal, has resulted in excess productive capacity, leading in turn to intense competition

Table 8-3

Coal Exports and Imports in 1985

	Megatonnes	Petajoules	Percent
Exports			
Nova Scotia	0.5	13.5	2
Alberta	5.4	158.9	20
British Columbia	21.5	629.7	78
Canada	27.4	802.1	100
Imports			
Quebec	0.5	15.8	3
Ontario	14.4	421.4	97
Canada	14.9	437.2	100

Note: The numbers in this table have been rounded.

Source: Statistics Canada, cat. no. 45-002.

among coal exporters. This significantly reduced new export opportunities as the profitability of Canadian coal exports, with their high transportation costs in western Canada and high operating costs in eastern Canada, was severely eroded by these events.

In projecting future coal exports we assume that under both price scenarios metallurgical coal exports will remain at current levels until 1990. At that time demand may be such as to warrant development of new mines in Canada. From 1990 to 2005 we project a two percent growth in Canadian metallurgical coal exports for both price cases. This could be conservative in the low price case.

Thermal coal exports, though only 18 percent of total exports in 1985, are projected to grow by about three percent per year in the high price case. In the low price case demand would respond to higher economic growth, but the impact on coal demand would tend to be offset by a loss of market share to low priced oil. Consequently, we have also projected three percent annual growth for thermal coal exports in the low price case.

Total coal exports show continued growth and reach 39 megatonnes by 2005.

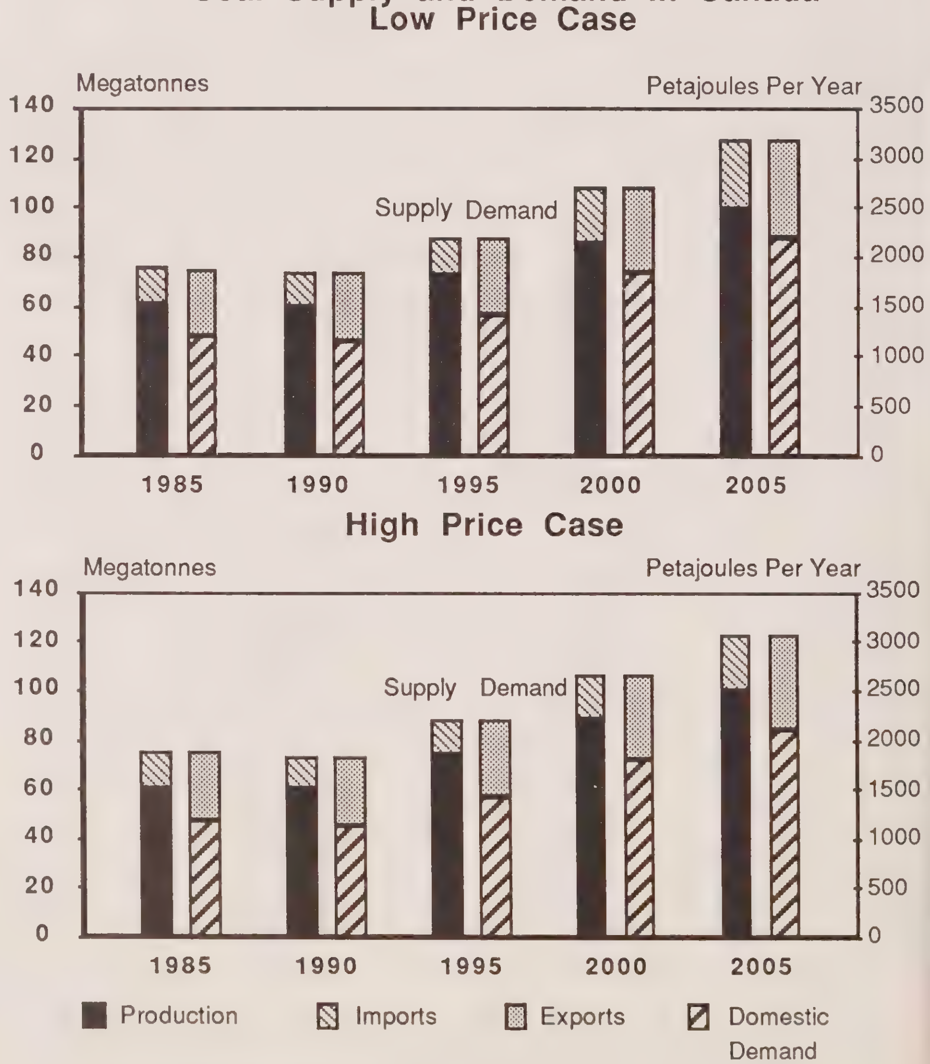
Coal imports have been relatively stable for the last 20 years, ranging generally between 14 and 17 megatonnes per year (Appendix Table A8-1). In 1985 imports were 15 megatonnes, 97 percent of which were to Ontario. Thermal coal, used by Ontario Hydro, accounted for 57 percent of total imports. Future coal imports will depend largely on Ontario's coal demand, previously discussed.

Over the study period, imports of metallurgical coal (which amounted to 6.3 megatonnes in 1985) grow 85 percent in the low price case and 65 percent in the high price case, to 12 megatonnes and 11 megatonnes respectively, reflecting the demand of Ontario's steel industry.

Total imports of thermal and metallurgical coal are expected to reach 27 megatonnes by the year 2005 in the low price case and 23 megatonnes in the high price case. These projections are based on a continuation of the existing situation in which western coal is not quite competitive in Ontario with imports from the U.S. However, producers in western Canada have shown a strong interest in displacing high sulphur imported coal with low sulphur domestic coal. Consequently, imports could be lower than anticipated if the high cost of controlling sulphur emissions and reduced transporta-

Figure 8-1

Coal Supply and Demand in Canada



Source: Appendix Table A8-3

tion cost are such as to improve the competitive position of western coal.

8.4 Supply/Demand Balances

Figure 8-1 shows the supply and demand balances for both the low and high price cases. (Thermal and metallurgical coal balances are provided in Appendix Table A8-3.) As shown in this figure, Canada is expected to continue to be a net coal exporter during the outlook period in both price cases.

In the low price case, as discussed in Chapter 3, domestic demand increases from 48 megatonnes in 1985 to 89 megatonnes in 2005 and total production grows from 61 megatonnes to 101 megatonnes for the same period. Net coal exports, which were about 13 megatonnes in 1985, are projected to increase to about 16 megatonnes by 1995. However, if our assumption of increased imports to Ontario during the latter part of the review period is valid, net exports should return to current levels by 2005.

In the high price case domestic demand increases from 48 megatonnes in 1985 to 84 megatonnes in 2005. Total production over the same time frame grows from 61 to 100 megatonnes. Net coal exports are projected to increase from 13 to 15 megatonnes in 1995 and continue to grow to just over 16 megatonnes in 2005 because of lower imports than in the low price case.

Chapter 9
Sources and Uses of Primary Energy

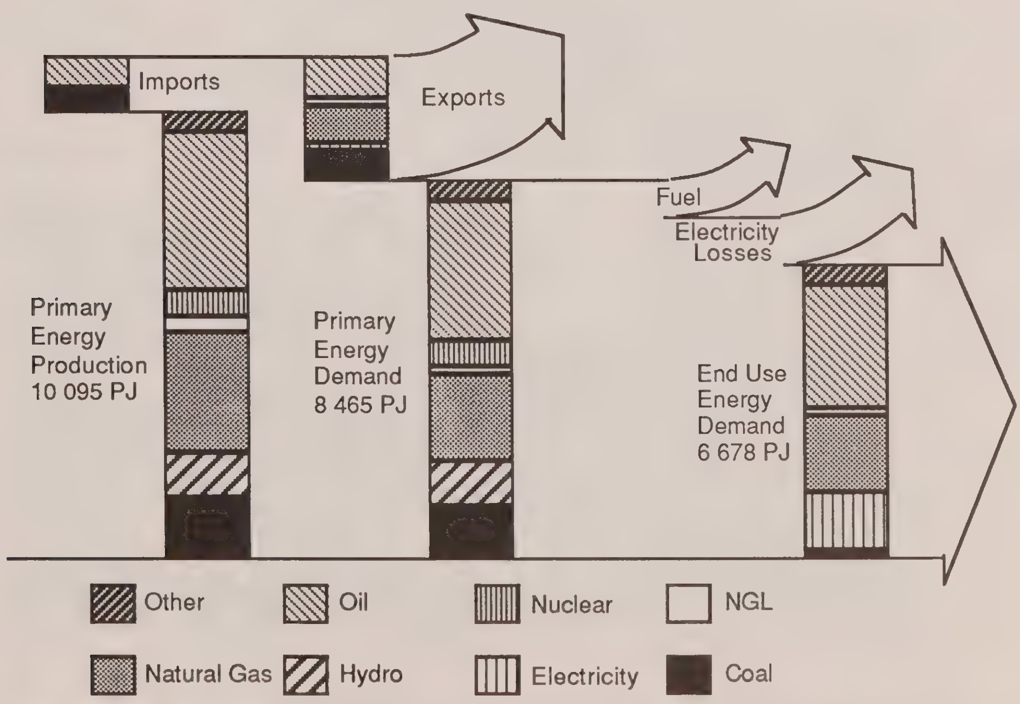
This chapter outlines the sources and disposition of energy flows in Canada at the present time, and draws together the implications of the analysis of preceding chapters for the evolution of those flows between now and 2005. The analysis is conducted in terms of primary energy, i.e., in terms of the total quantities of the various energy forms used in the country.

Figure 9-1 shows the relationships among end use energy demand, primary energy demand and energy production in Canada in 1984. To arrive at the amount of primary energy used, we add to end use demand the amount of fuel and losses associated with the production and distribution of energy, which include:

- fuel needed to produce and move oil and natural gas to markets;
- fuel and losses incurred in the refining of crude oil to produce petroleum products, and the reprocessing of gas to remove natural gas liquids;
- utility own use and losses in the transmission and distribution of electrical power;
- conversion losses in electricity generation when coal, gas, oil and uranium are consumed in generating plants; approximately three units of fuel input are needed to produce one unit of electricity (specifically, we are using a conversion factor of 10.5 petajoules per terawatt hour for electricity generated from fossil fuels and 12.1 petajoules per terawatt hour for electricity generated from uranium[1]).

1. This is a different conversion factor for electricity generated from nuclear sources than was used in the September 1984 Report. At that time it was assumed that the amount of primary energy associated with nuclear energy was the amount which would have been required if fossil fuels had been used, implying a conversion factor of 10.5 petajoules per terawatt hour. The present treatment reflects the reality that Canada will not likely revert to fossil fuels to generate the quantities of electricity now being generated by CANDU reactors.

Figure 9-1
Energy Flows
(Based on 1984 Data)



Note: Hydro electricity converted to PJ using 3.6 PJ/TW.h and nuclear electricity converted to PJ using 12.1 PJ/TW.h

Since no fuels are used to generate hydro electricity, there are two ways of calculating the primary energy associated with hydro power.

- We can define its primary energy as the energy produced at the dam site. Measured in this way the primary energy associated with the production of hydro electricity would be equal to the energy content of the electricity output, 3.6 petajoules per terawatt hour. For convenience we label this the energy output method.[1]
- A second method is frequently used, particularly when comparisons are being made of energy use across countries. This method (labelled the fossil fuel equivalence method) assumes that the amount of primary energy associated with hydro electricity is the amount which would be required if fossil fuels were used. Using this method a conversion factor of 10.5 petajoules per terawatt hour is adopted because methods of generation using fossil fuels have, on average, an efficiency of about 33 percent.

Use of the second method implies that the amount of primary energy attributed to hydro will be much larger than the amount of electrical energy produced. It is, however, not relevant for Canada; we have large hydro resources and will not replace our hydro-generated electricity with electricity generated from fossil fuels. We therefore use the energy output method in this report.

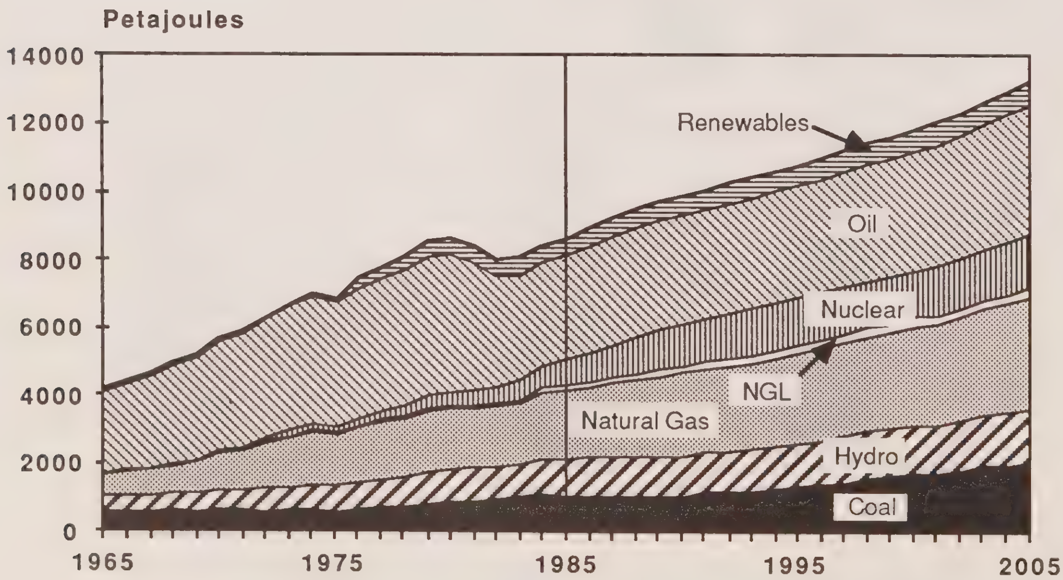
However, because the fossil fuel equivalence conversion is widely used for international comparisons, we show our international comparisons in Section 9.3 on both bases.

The arrow labelled fuel in Figure 9-1 shows the heat content of fuels used in the production and transportation of final energy other than fossil fuels used in the production of electricity.

About seven-eighths of the electricity losses shown in the figure result from the use of conventional fuels and uranium to generate electricity.

1. In the September 1984 Report, we also converted nuclear-generated electricity at a rate of 3.6 petajoules per terawatt hour in calculations using the energy output method.

Figure 9-2
Primary Energy Demand
History and Low Price Case Projection



Source: Appendix Table A3-2
Note: Hydro electricity converted to PJ using 3.6 PJ/TW.h
Nuclear electricity converted to PJ using 12.1 PJ/TW.h

The remaining one-eighth results from transmission losses.

The distribution across energy forms of primary and end use energy is quite different, and primary energy is larger than end use energy. The primary demand for coal is much larger than its end use demand because primary coal demand includes the quantities used to generate electricity. Only minor amounts of oil and gas are used for this purpose.

Primary energy production in Canada will differ from primary domestic energy demand to the extent that we are net importers or exporters of energy. As shown in Table 9-1, in 1985 Canada was a net exporter of natural gas, petroleum, coal, natural gas liquids, and electricity.

9.1 Projections of Primary Energy Demand and Production

Primary Energy Demand

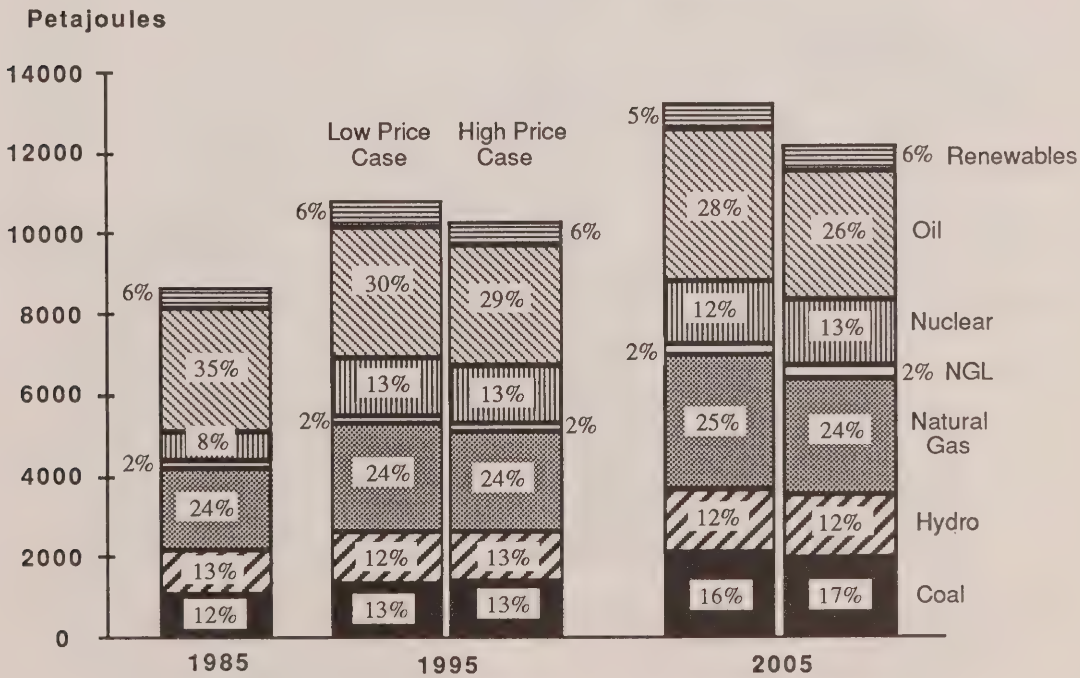
Figure 9-2 shows the projected evolution of the components of primary energy demand over our projection horizon for the low price case, along with historical data. Our low and high price case projections are compared in Figure 9-3.

The share of hydro-generated electricity in primary demand is lower than its share of end use demand because of its high conversion efficiency. (The shares of hydro in primary demand shown here are less than those in the September 1984 Report. At that time we used the fossil fuel equivalence method to calculate the primary energy associated with hydro electricity.)

The growth and pattern of primary energy over our projection horizon largely reflect the projected evolution of end use requirements described in previous chapters. The distribution of primary energy is projected to shift towards nuclear-generated electricity and coal and substantially away from oil by 2005. The change in the distribution is broadly similar for both price cases,

Figure 9-3

Comparison of Primary Energy Demand Projections



Source: Appendix Table A3-2

Note: Hydro electricity converted to PJ using 3.6 PJ/TW.h
Nuclear electricity converted to PJ using 12.1 PJ/TW.h

but it is more pronounced in the high price case.

Primary Energy Production

Historical data and our projections for the distribution of primary energy production are shown in Figures 9-4 and 9-5. In the low price case the shares of oil and gas production are projected to be substantially smaller in 2005, and shares for other energy forms (except NGL) larger, than are the corresponding shares for primary energy demand. This reflects the projected declines in gas and conventional light oil production over the review period. In the high price case there are only small differences between the shares of energy demand and production projected to be held by each energy source.

9.2 Net Exports of Energy

Since the last half of the 1960s, Canada has produced energy in excess of its needs and has become a large net exporter of energy. In 1985 the value of net energy exports from Canada was some $10.7 billion.

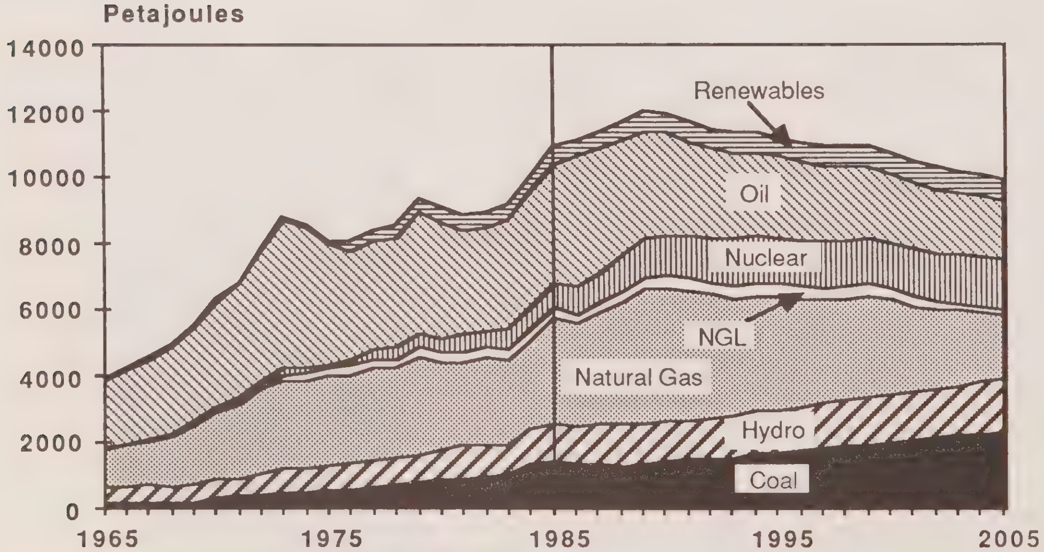
Table 9-1 provides historical data on net energy exports and summarizes the prospects for energy balances in each price case. The numbers shown for natural gas in 1995 are qualitatively different from those shown for other energy sources in that they include only projected exports under current licence authorizations. Natural gas exports in the mid-1990s could be appreciably larger than the amounts shown under both price scenarios. For electricity the energy balance numbers include potential exports beyond those currently authorized by the Board. Trade in oil, NGL and coal is unrestricted.

Our projections suggest that over the next ten years Canada will continue to be a net energy exporter. In the low price case, Canada becomes a net importer of energy by the end of the study period; in the high price case the potential exists for continuing substantial net exports of energy through 2005.

Figure 9-4

Primary Energy Production

History and Low Price Case Projection



Sources: Renewables: Appendix Table A3-2
Oil: Appendix Table A6-18
NGL: Appendix Table A7-2
Natural Gas: Appendix Table A5-8
Hydro and Nuclear: Appendix Table A4-5
Coal : Appendix Table A8-3

Note: Hydro electricity converted to PJ using 3.6 PJ/TW.h and nuclear electricity converted to PJ using 12.1 PJ/TW.h

Canada has been a net exporter of coal since 1981 after having been a net importer for many years. A substantial increase in coal exports is projected, primarily from western Canada. In the low price case, this increase is expected to be offset by increased imports into Ontario during the latter part of the study period.

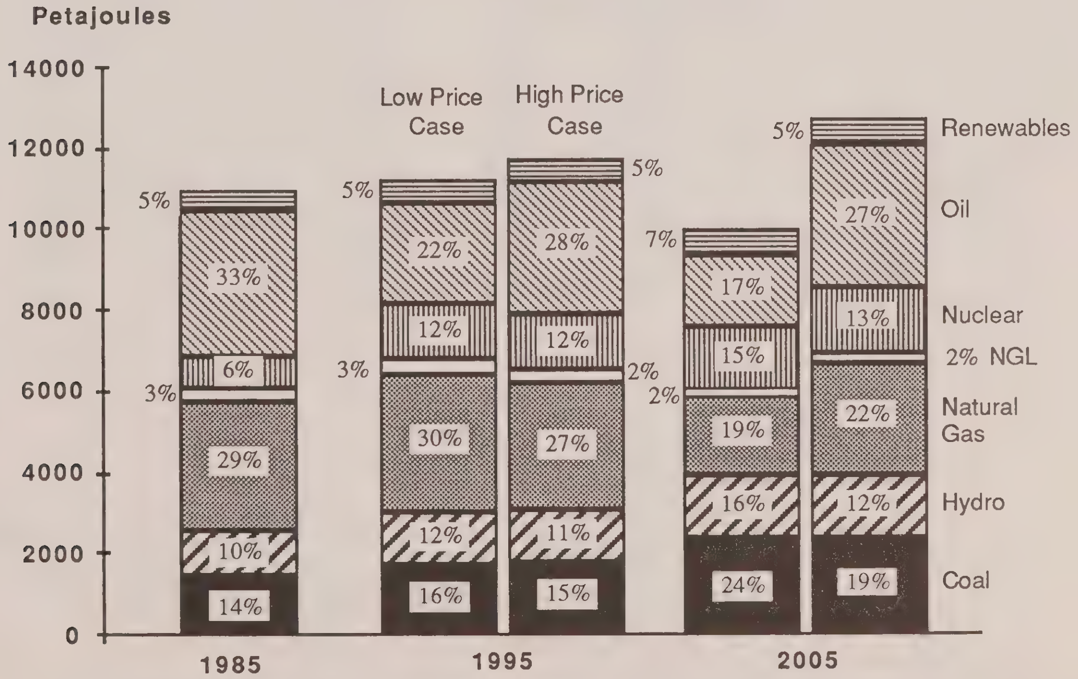
Exports of electricity have increased substantially in recent years. About three-quarters of export sales are interruptible energy. There is growing interest among some utilities in Canada and the U.S. for additional firm power exports to meet a small portion of United States additional capacity requirements in the 1990s. Our projections include estimates of such potential firm exports, which would bring firm sales to almost half of the projected total electricity exports in 2005. We estimate that total exports of electricity will increase in both price cases until the late 1990s. After that, exports will decrease slightly as Canadian needs increase and surpluses shrink.

Natural gas exports are projected to rise rapidly in the remaining years of this decade to about 80 percent of currently authorized levels by 1990, about 45 percent above 1985 levels. By the end of the review period domestic requirements exceed domestic supply in both price cases. This gap could be closed either by imports of gas or by changes in relative prices which would constrain domestic demand, induce substitution of other energy sources for natural gas and induce more domestic supply of gas.

NGL have for some time been produced in excess of Canadian requirements. For liquids other than pentanes plus this is likely to con-

Figure 9-5

Comparison of Primary Energy Production Projections



Sources: Renewables: Appendix Table A3-2
Oil: Appendix Table A6-18
NGL: Appendix Table A7-2
Natural Gas: Appendix Table A5-8
Hydro and Nuclear: Appendix Table A4-5
Coal: Appendix Table A8-3

Note: Hydro electricity converted to PJ using 3.6 PJ/TW.h and nuclear electricity converted to PJ using 12.1 PJ/TW.h

tinue over the next 10 years. Quantities available for export are projected to decline as Canadian demand rises relative to supply. In the later years of the review period, we project requirements above the expected supply in the low price case, but a balance between domestic supply and requirements in the high price case. In the low price case, the gap will probably be closed by the use of substitutes.

Net exports of petroleum (crude oil and oil products) are likely to decline as domestic demand outpaces productive capacity. In the low price case, substantial requirements for imports of both crude oil and petroleum products are projected in the latter half of the review period. In the high price case we estimate that net exports of both total crude oil and products will be possible through to 2005, but at substantially lower levels than in 1985. Exports of heavy crude oil are larger than the imports of light crude oil in the high price case.

9.3 International Perspectives

Table 9-2 compares energy use, including petrochemical feedstocks, and production in Canada in 1984 with that in other Organization for Economic Co-operation and Development (OECD) member countries. In this table, we have used OECD data which converts nuclear electricity to primary energy at 10.5 petajoules per terawatt hour. For hydro electricity both the energy output and fossil fuel equivalence methods (discussed above) are shown for comparison.

Table 9-1

Energy Balances

(Petajoules)

	Net Energy Exports (Imports)			Excess Supply (Demand) [c]			
				Low Price Case		High Price Case	
	1965	1975	1985	1995	2005	1995	2005
Coal	(422)	(146)	365	382	281	416	399
Electricity [a]	–	11	147	188	180	227	198
Natural Gas	430	1040	990	526 [d]	(1551)	526 [d]	(310)
NGL	34	147	163	153	(105)	71	8
Petroleum [b]	(567)	(111)	623	(945)	(2132)	156	185
Total	(525)	941	2288	304	(3327)	1396	480

-- Too small to be expressed.

Sources: Coal: Appendix Table A8-3
Electricity: Appendix Table A4-8
Natural Gas: Appendix Table A5-8
NGL: Appendix Tables A7-10 to 12
Petroleum: Appendix Table A6-17

Note: The numbers in this table have been rounded.

[a] Hydro and nuclear electricity converted to PJ using 3.6 PJ per TW.h. Electricity excludes exchanges involving no net imports or exports.
[b] Petroleum includes crude oil and refined petroleum products, but excludes exchanges involving no net imports or exports.
[c] Excess supply is indicative of potential exports. Excess demand is indicative of a requirement which may be met by one or a combination of: importing, substituting other energy sources, and/or developing larger domestic supplies. For the latter two forms of adjustment to occur, relative prices would have to change to provide the necessary incentives to alter consumption and production.
[d] Includes only projected exports under existing licences.

TABLE 9 - 2

Comparison of Energy Use and Production in OECD Countries in 1984

	Population	Gross Domestic Product	Primary Demand [a]	Production [a]	Primary Demand: Energy Output [a] Per Capita	Energy Output [a] Per GDP	Fossil Fuel Equivalence [b] Per Capita	Fossil Fuel Equivalence [b] Per GDP	Average Annual Change in Primary Energy Demand [c] Per Unit of GDP [d] 1973 - 1984
	(Millions) (1)	($C,Billions) (2)	(PJ) (3)	(PJ) (4)	(GJ) (5)	(MJ) (6)	(GJ) (7)	(MJ) (8)	Percent (9)
Australia	15.5	225	3057	4632	197	14	202	14	-0.2
Austria	7.6	83	952	307	125	11	148	13	-1.3
Belgium	9.9	98	1730	458	175	18	176	18	-2.6
CANADA	25.2	433	7730	9445	307	18	372	22	-0.6
Denmark	5.1	71	720	127	141	10	141	10	-2.8
Finland	4.9	66	989	411	202	15	218	16	n.a.
France	54.9	634	7617	2899	139	12	146	13	n.a.
Germany	61.2	794	10924	5284	178	14	180	14	-1.8
Greece	9.9	43	716	269	72	17	74	17	1.0
Iceland	0.2	3	39	14	193	12	308	18	n.a.
Ireland	3.5	23	355	155	102	16	103	16	-2.0
Italy	57.0	451	5415	883	95	12	100	13	-1.6
Japan	120.0	1625	15274	2190	127	9	132	10	-2.8
Luxembourg	0.4	4	130	3	324	30	331	30	-5.1
Netherlands	14.4	159	2555	2677	177	16	177	16	-1.9
New Zealand	3.3	30	409	298	124	14	161	18	1.4
Norway	4.1	71	822	2919	200	12	270	16	-1.1
Portugal	10.1	25	474	76	47	19	53	21	1.8
Spain	38.4	208	2870	1010	75	14	80	15	0.5
Sweden	8.3	123	1667	934	201	14	248	17	-1.3
Switzerland	6.5	118	880	313	135	7	163	9	0.2
Turkey	48.8	64	1509	830	31	23	32	25	-1.2
U.K.	56.5	548	7996	8516	142	15	142	15	-2.3
U.S.	236.7	4706	73449	66231	310	16	318	16	-2.1
Total	802.4	10605	148279	110880	n.a.	n.a.	n.a.	n.a.	-1.9 [e]
Canada - percentage of total	3.1%	4.1%	5.2%	8.5%	n.a.	n.a.	n.a.	n.a.	n.a.
- rank	9 th	7 th	5 th	2 nd	3 rd	4 th	1 st	3 rd	15 th

Sources: Columns (1) to (8): OECD, Energy Balances of OECD Countries 1983/1984; Paris, 1986.
OECD Observer No. 139; Paris, March 1986, pages 16 to 19.
Column (9): International Energy Agency, Energy Policies and Programmes of IEA Countries, 1985 Review; Paris, 1986, page 136.

n.a. not available

Note: The numbers in this table have been rounded.

[a] Hydro electricity converted to PJ using 3.6 PJ per TW.h, and nuclear electricity converted to PJ using 10.5 PJ per TW.h.
[b] Hydro and nuclear electricity converted to PJ using 10.5 PJ per TW.h.
[c] Primary energy demand measured in metric tonnes of oil equivalent.
[d] GDP measured in billions of 1980 U.S. dollars.
[e] Excludes Finland, France, and Iceland.

In 1984, Canada was 9th largest in population, 7th in gross domestic product, 5th in primary demand for energy, and second in energy production.

On a per capita basis Canada was the third largest energy consumer of any OECD country in 1984, and was fourth largest on a per unit of gross domestic product basis.

As shown in Table 9-2, with hydro electricity measured using the fossil fuel equivalence method, Canadian energy use per capita and per dollar of output would be about one-fifth higher than if measured using the energy output method, and Canadian energy consumption would be perceived to be substantially higher than that of the United States, instead of about the same.

Canadian consumption of energy is high for a number of reasons, including our cold climate; low population density; the large distances over which people and goods must be transported; the concentration of manufacturing of energy intensive products such as aluminium, wood pulp, newsprint and petroleum products; and the extent of mining of minerals. Generally, this concentration of energy intensive industries reflects our favourable energy resource endowment and relatively low prices for electricity, natural gas and several other energy resources.

Only five OECD countries produced more primary energy than they used in 1984. These were (with production in excess of demand in PJ in parentheses): Norway (2097), Canada (1715), Australia (1575), United Kingdom (520), and the Netherlands (122). In 1984, Canada produced about 22 percent more energy than it consumed.

The final column of Table 9-2 compares changes in energy efficiency from 1973 to 1984, in terms of average annual changes in primary energy demand per unit of gross domestic product. Although Canada's energy efficiency improved over this period, Canada's improvement was 15th out of the 21 countries compared.

Chapter 10 Conclusions

At the time the September 1984 Report was prepared, world energy markets were characterized by substantial excess supply of all energy commodities. The world price of oil had been declining in real terms since 1981 and there were the beginnings of a spot market for natural gas in the U.S.

Since then, the excess supply has continued and there have been major developments in oil and gas markets which have made the analysis for this report even more difficult than was the case in 1984. In oil markets the real price of oil continued its gradual decline through 1985 and dropped precipitously in early 1986. The factors underlying this experience may reflect longer term supply and demand conditions. As a consequence, the world oil price projections on which this report is based are much lower than those used in 1984.

There have been major moves in both Canada and the U.S. to reduce the regulation of natural gas. At the time this report was prepared the process of deregulation was still underway in both countries and it remained unclear as to how competitive markets would function. In particular, it was not yet clear how natural gas prices to different end users would be determined.

As a result it proved particularly difficult to determine appropriate paths for natural gas prices. The framework we have used relates the price of natural gas to that of heavy fuel oil. There is, however, a reasonable probability that natural gas prices will be higher than those on which we have based the analysis of this report. Thus natural gas supply and requirements could differ from our projections depending on how gas marketing evolves.

Even though there is uncertainty associated with our assumptions, our results suggest a number of plausible conclusions about energy demand, markets for particular energy sources and the overall energy future for Canada.

Demand

Fundamentally our demand analysis is based on the judgement that the heightened "energy consciousness" of consumers, which resulted from the supply disruptions and price shocks of recent years, will continue, notwithstanding the prospect of lower prices. It also reflects the view that, to a very large extent, the factors which generated the substantial declines of energy intensity in recent years are irreversible. These declines resulted to a great extent from the development of new technology which is now embodied in buildings, machinery and other equipment so that, for some years to come, energy use can only decline relative to production as older durable goods are replaced with new, more energy efficient, equipment. There are, no doubt, limits to the decline in energy intensity but, in our view, we are some distance from them. Lower energy prices may slow the growth of energy conservation but there are good reasons to believe that there will not be a reversal of overall energy intensity.

Given the two energy price and economic growth projections used in this report, the rate of growth in total Canadian end use energy demand varies between 1.5 and 1.9 percent per year between 1984 and 2005. Our assessment is that energy demand will grow less rapidly than the overall growth rate of the economy and that gains in energy conservation will continue to be made even if world oil prices follow a course similar to that of our low price case. Indeed, it is possible that energy use could grow at rates even lower than these, if, for example, economic activity shifts further in the direction of the service producing industries which tend to be less energy intensive than those producing goods, or if economic activity turns out to be lower than projected.

Our demand projections suggest that there will continue to be a shift off oil, even in the low price case, and that this fuel will be increasingly confined to its captive market, transportation. By 2005 the share of oil in overall energy use drops to 33 percent of end use demand from 41 percent in 1984. Concomitantly, the shares of natural gas and electricity are projected to rise.

Our analysis suggests that, though conservation gains will continue to be made, alternative energy forms are unlikely to comprise a greater share of the energy market in 2005 than they do now. This follows directly from the current relatively low price levels of conventional energy and from the low projected rates of price increase on which our analysis is based.

Supply

Our projections for supply of light crude oil and natural gas in this report are lower over the study period than those of the September 1984 Report. Supply of heavy crude oil, however, is higher (in the high price case) because of a more optimistic outlook for the development of bitumen production from in situ projects.

For light crude oil and equivalent, we project a decline in productive capacity to 40 percent of the 1985 level by 2005 in the low price case, and to 63 percent in the high price case.

For natural gas, productive capacity in western Canada is likely to depend increasingly on reserves in smaller pools. In both price cases natural gas productive capacity is projected to decline substantially over the review period. In neither scenario do we include natural gas from the frontier regions.

It is probable that we have already extracted the cheapest oil and gas from the conventional producing areas. New reserves of oil and natural gas are becoming increasingly costly and difficult to find.

The fact that reserves of oil and gas from conventional producing areas are being depleted implies that, to sustain supply, Canada will have to develop production from frontier regions, which is expensive to find, develop and transport; production of synthetic oil from mineable oil sands deposits, which is expensive; and bitumen from in situ projects which, without upgrading, is not compatible with current refinery configurations in Canada.

Given our price projections there are relatively few major projects and only limited frontier supplies expected to be developed over our study period. In the high price case, new sources of light crude oil beyond our traditional supply are likely to be confined to production from Hibernia and the Beaufort Sea and limited upgrading of heavy crude oil and bitumen. No new major projects are included in the low oil price scenario beyond the one heavy crude oil upgrader now under construction in Saskatchewan.

It is difficult to assess the extent to which bitumen or heavy crude oil will be upgraded to synthetic light crude. The oil sands resource is known and recoverable quantities are very large. The issue is whether expected price/cost relationships are such as to make the production of light crude economically viable. Oil sands mining plants (such as Syncrude and Suncor) are large scale operations subject to substantial economic risk. Our estimates of construction and operating costs suggest that, in our high price case, new plants are in the range of being economically viable; however, there is very little margin for error in either the cost estimates or revenue expectations. Because these plants require very large up-front investment and considerable lead time, and because there is much uncertainty about both ultimate costs and oil prices, we do not assume that major new capacity will be constructed. However, cost reduction, improved technology and a sustained period of attractive oil prices could stimulate investor confidence and lead to the construction of new or expanded oil sands plants during the next twenty years.

The prospects for upgrading of bitumen produced by in situ methods are more favorable and, in the high price case, we have allowed for the construction of two upgraders in addition to the one now under construction in Saskatchewan. As in the case of oil sands mining plants, changing perceptions of risk and improved price/cost relationships could result in more upgrading capacity being constructed over the study period than we have allowed for.

Our natural gas price and supply projections for Canada may well prove to be low. Should gas prices rise relative to oil prices or follow what we have termed a price differentiation scenario, rather than track heavy fuel oil prices as we have assumed, there could well be a faster rate of development of the gas potential of Western Canadian and frontier sources. Moreover, in these circumstances domestic demand would be lower and the potential for natural gas exports greater than projected.

For coal and electricity, the prospects are more favorable. Canada is endowed with abundant resources of coal, hydro, and uranium. The real cost of electricity from new plants may increase gradually over the study period but there is little prospect of supply problems or major price increases.

Energy price and cost relationships are critical to the results of our supply analysis and we have stressed the uncertainties associated with world oil price prospects.

There are also uncertainties about the prospects for costs of development and production. Technological progress will be made which should reduce supply costs over time. It may also be true that our cost estimates, based as they are largely on the experience of a period of severe inflation, have overestimated the potential costs of future energy supply, thereby leading us to underestimate its availability.

Energy Balances and Implications

In both price cases it is probable that Canada will become increasingly dependent on imports of light crude oil as time goes on. This dependency could be reduced substantially in the high price case if more heavy oil upgraders were to be constructed than we have allowed for. In the low price case imported crude oil would be needed in Ontario.

Canada currently is a net exporter of petroleum products. This is likely to reverse in the 1990s in the low price

case in which substantial imports of petroleum products appear to be required by 2005. However, in the high price case, Canada continues to be a net exporter of petroleum products (albeit in progressively decreasing quantities) throughout the review period.

An excess supply of heavy crude oil is likely to continue in both scenarios. The excess supply decreases in the low price case but increases substantially in the high price case.

A question often arises about Canada's longer term self-sufficiency in oil. Self-sufficiency in oil does not necessarily imply equality between domestic production and use for each category of crude oil and oil products. In the low price case the potential exports of heavy crude oil are less than required imports of light crude oil and petroleum products. In the high price case, potential exports of heavy crude oil and petroleum products are larger than estimated imports of light crude oil. The role of international trade in balancing supply and demand for light and heavy oil would be reduced if there were more domestic upgrading than we have allowed for.

For natural gas, we project that, in both price cases, supplies from the conventional areas will meet demand, including exports under existing authorizations, until 2000 or beyond. Our projections, being based on natural gas prices assumed to be the same for all customer classes, may well understate future prices, surpluses and potential exports. The projected crossovers are an indication that some adjustment will be required to balance supply and demand, perhaps including an increase in the price of natural gas relative to oil.

The balances for ethane, propane and butanes broadly follow those for natural gas. For pentanes plus excess demand, largely attributable to the requirement for diluent, could occur as early as 1989 in the high price case. The demand for diluent which cannot be met by domestic pentanes plus may be met by imports or by substituting light crude oil or refined naphthas.

Canada is likely to continue to be a net exporter of coal in both oil price cases because of the projected net exports of metallurgical coal. The extent of our exports will depend on our production and transportation costs relative to those of other countries.

In both price cases electricity exports grow into the 1990s and then decrease slightly from these higher levels toward the end of the review period.

A major question is the extent to which electricity generation and transmission capacity will be developed more rapidly than required for domestic use, in response to U.S. demand for power from Canada. We have included in our projections potential exports of this kind from British Columbia, Manitoba and Quebec, though plans and negotiations are in all cases still underway. The other key issue, with implications for primary energy demand, is whether future electricity generating capacity will be based on hydro, nuclear or coal plants, especially in Ontario. Increased use of coal would have important implications for coal imports, Canadian production, or both.

Overall, our analysis suggests that, electricity and coal excepted, the energy choices for Canada over the study period and beyond are to develop hydrocarbons from the frontier areas, to import them or to develop domestic substitutes from unconventional sources. It is likely that all three options will increasingly be required to compensate for the depletion of the resources of Western Canada and provide a measure of energy security.

The existence of frontier and unconventional resources is not in question; the issue is whether these resources can be viably developed given prospects for future price/cost relationships. If our price paths were to prevail, given the present state of technology, and assuming that our supply cost estimates are generally valid, it is not certain that these resources would be developed on a large scale.

Energy security can also result from conservation. Our demand analysis shows that, given time and the appropriate pricing signals, there is scope for continuing substitution among energy forms. This observation leads to another: we have started with price projections for individual energy sources and developed the implications of these and other assumptions for the supply and demand of individual energy commodities. But individual energy markets do not operate in isolation; there are complex and continuing interactions among them which collectively operate to equate supply and demand for energy as a whole.

The real issue is not whether energy markets will adjust; given time it is likely that they will. The issue for energy security is whether or not the adjustment process will be timely and effective, to avoid temporary scarcities of particular energy forms on which consumers depend. Several factors could interfere with the adjustment process. For example, it is not certain that over the next twenty years the pricing system will necessarily deliver appropriate signals to producers and consumers; and there could be disruptions in

world markets so severe that price changes alone may not be able to equilibrate demand and supply in the short term.

Our study was not intended to assess either the nature or the adequacy of adjustment processes in energy markets. Rather it was designed to elucidate where pressure points might occur.

We have noted that demand pressure can be alleviated by a number of means; it does not necessarily follow that an increase in domestic supply of the commodity in question is either required or desirable. Substitution of one energy source for another and energy conservation can and will occur in the future as they have in the past. To determine the desirability of self-sufficiency in any energy form would require an assessment of the net costs or benefits of such a goal, a task which was beyond the scope of this study.

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Appendix 1

Table A1-1
Abbreviations of Names, Terms and Units

	Names
"Act"	The National Energy Board Act
"ANG"	Alberta Natural Gas Company Limited
"A & S"	Alberta and Southern Gas Company Limited
"(the) Board" or "NEB"	(the) National Energy Board
"CANMET"	Canadian Centre for Mineral and Energy Technology
"COGLA"	Canadian Oil and Gas Lands Administration
"CPA"	Canadian Petroleum Association
"El Paso"	El Paso Natural Gas Company
"FERC"	Federal Energy Regulatory Commission
"GSC"	Geological Survey of Canada
"IPL" or "Interprovincial"	Interprovincial Pipe Line Limited
"LOOP"	Louisiana Offshore Oil Port
"NGPA"	Natural Gas Policy Act (U.S.)
"Northwest"	Northwest Pipeline Corporation
"OECD"	Organization for Economic Cooperation and Development
"OPEC"	Organization of Petroleum Exporting Countries
"Pan-Alberta"	Pan-Alberta Gas Limited
"PGT"	Pacific Gas Transmission Company
"PG & E"	Pacific Gas and Electric
"September 1984 Report"	*Canadian Energy Supply and Demand 1983-2005* Technical Report and Summary Report, National Energy Board, September, 1984
"SoCal"	Southern California Gas Company
"TCPL" or "TransCanada"	TransCanada PipeLines Limited
"TransMountain"	TransMountain Pipe Line Company Limited
"U.S."	United States
"WTCL" or "Westcoast"	Westcoast Transmission Company Limited

Table A1-1 (Continued)
Abbreviations of Names, Terms and Units

Terms

BER	Beyond Economic Reach
CPE	Centrally Planned Economies
EOR	Enhanced Oil Recovery
GDP	Gross Domestic Product
GNE	Gross National Expenditure
GNP	Gross National Product
LPG	Liquefied Petroleum Gases
NGL	Natural Gas Liquids
NGV	Natural Gas for Vehicles
RDP	Real Domestic Product

Units

Prefix	Multiple	Symbol
kilo-	10^3	k
mega-	10^6	M
giga-	10^9	G
tera-	10^{12}	T
peta-	10^{15}	P
exa-	10^{18}	E

Btu	=	British thermal unit
Bcf	=	Billion cubic feet
Tcf	=	Trillion cubic feet
$C	=	Canadian dollars
$US	=	United States dollars

GJ	gigajoule	=	10^9Joules
TJ	terajoule	=	10^{12}J
PJ	petajoule	=	10^{15}J
EJ	exajoule	=	10^{18}J
kW	kilowatt	=	10^3Watts
kW.h	kilowatt hour	=	10^3W.h
MW	megawatt	=	10^3kW
MW.h	megawatt hour	=	10^3kW.h
GW	gigawatt	=	10^6kW
GW.h	gigawatt hour	=	10^6kW.h
TW	terawatt	=	10^9kW
TW.h	terawatt hour	=	10^9kW.h

Conversion Factors

Metric	Imperial Equivalent Units
1 cubic metre of oil	
(15°C and 922 kg/m^3)	= 6.292 26 barrels (60°F and 22°API)
(15°C and 855 kg/m^3)	= 6.292 58 barrels (60°F and 34°API)
(15°C and 739 kg/m^3)	= 6.294 03 barrels (equilibrium pressure, 60°F and 60°API)
1 cubic metre of natural gas (101.325 kilopascals and 15°C)	= 35.301 01 cubic feet (14.73 psia and 60°F)
1 cubic metre of ethane (equilibrium pressure and 15°C)	= 6.330 barrels of ethane (equilibrium pressure and 60°F)
	= 9.930 thousand cubic feet of ethane gas (14.73 psia and 60°F)
1 cubic metre of propane (equilibrium pressure and 15°C)	= 6.300 0 barrels of propane (equilibrium pressure and 60°F)
1 cubic metre of butanes (equilibrium pressure and 15°C)	= 6.296 8 barrels of butanes (equilibrium pressure and 60°F)
1 tonne	= 1.102 311 tons
1 kilojoule	= 0.948 213 3 British thermal units (Btu)
1 gigajoule (GJ)	= approximately 0.95 million Btu, or 0.95 thousand cubic feet of natural gas at 1000 Btu/cf
1 petajoule (PJ)	= approximately 0.95 billion cubic feet of natural gas, or 165 000 barrels of oil, or 0.28 terawatt hours of electricity

Table A1-2 (Continued)
Conversion Factors

Gross Energy Content Factors

Natural Gas		
B.C.	- domestic	39.10 MJ/m^3
	- Huntingdon	39.10 MJ/m^3
	- Kingsgate	37.65 MJ/m^3
	- Grassy Point	38.20 MJ/m^3
Alberta	- domestic	38.80 MJ/m^3
	- Cardston	37.65 MJ/m^3
	- Aden	36.06 MJ/m^3
East of Alberta		37.65 MJ/m^3
Ethane (liquid)		18.36 GJ/m^3
Propane (liquid)		25.53 GJ/m^3
Butanes (liquid)		28.62 GJ/m^3
Crude Oil		
Light and Medium		38.51 GJ/m^3
Heavy		40.90 GJ/m^3
Pentanes Plus		35.17 GJ/m^3
Coal		
Bituminous		29.30 GJ/tonne
Subbituminous		19.76 GJ/tonne
Lignite		15.35 GJ/tonne
Average domestic use		24.00 GJ/tonne

Petroleum Products	
Aviation Gasoline	33.52 GJ/m^3
Motor Gasoline	34.66 GJ/m^3
Petrochemical Feedstocks	35.17 GJ/m^3
Naphtha Specialties	35.17 GJ/m^3
Aviation Turbo	35.93 GJ/m^3
Kerosene	37.68 GJ/m^3
Diesel	38.68 GJ/m^3
Light Fuel Oil	38.68 GJ/m^3
Lubes and Greases	39.16 GJ/m^3
Heavy Fuel Oil	41.73 GJ/m^3
Still Gas	41.73 GJ/m^3
Asphalt	44.46 GJ/m^3
Petroleum Coke	42.38 GJ/m^3
Other Products	39.82 GJ/m^3
Electricity	
Secondary	3.6 MJ/kW.h
Primary Hydro	3.6 MJ/kW.h
Nuclear	12.1 MJ/kW.h

	Definitions
Associated Gas	Natural gas, commonly known as gas cap gas, which overlies and is in contact with crude oil in the reservoir.
Base Load Capacity	Electricity generating equipment which operates to supply the load over most hours of the year.
Basic Oxygen Furnace	A process used in steel making. In this process molten raw iron, with added lime, is subjected to jets of pure oxygen. The oxygen burns out the carbon to produce steel.
Beyond Economic Reach Reserves	Established reserves, which because of size, location or composition are not considered economically viable at the present time.
Biomass	Organic material such as wood, crop waste, municipal solid waste and mill waste, processed for energy production.
Bitumen	See 'Crude Bitumen'
Blowdown	The production of gas, either from the gas cap of an oil reservoir, normally after depletion of the oil, or from a cycled gas pool upon cessation of the cycling operation.
Capacity Available (Electricity)	The sum of the Installed Capacity in a system plus firm purchases.
Capacity (Electricity)	The maximum amount of power which a machine, apparatus or appliance can generate, utilize or transfer, expressed in kilowatts or some multiple thereof.
Carbon Dioxide (CO_2) Flooding	An enhanced recovery process in which carbon dioxide is injected into an oil reservoir to increase recovery.
Chemical Flooding	An enhanced recovery process in which water, with added chemicals, is injected into an oil reservoir to increase recovery.
Chemi-Thermo-Mechanical Pulping	Same as TMP but with chemicals being added to the chips to further refine the pulp by removing the lignin.
Coal Gasification	The production of a synthetic natural gas from coal.
Coal Liquefaction	The production of a synthetic crude oil or related liquid fuel from coal.
Co-generation	A facility which produces steam heat as well as electricity with a resultant overall improvement in energy conversion efficiency.
Condensate	As used in this report, synonymous with pentanes plus.
Continuous Casting	A process that directly casts molten steel in a primary mill into smaller and thinner sections without the need for reheating steel ingots.
Conventional Areas	Generally, the Western Provinces, Southwestern Ontario, and the southern part of the Yukon and Northwest Territories.
Conventional Producing Areas	Same as 'Conventional Areas'
Crude Bitumen	Very heavy crude oil or tar consisting of a naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and other minerals, and that in its natural viscous state is not recoverable at a commercial rate through a well.

Table A1-3 (Continued)
Definitions

Crude Oil and Equivalent Hydro-carbons	Sometimes referred to as 'Crude Oil and Equivalent'. Includes light and heavy crude oil, pentanes plus, bitumen and synthetic crude oil.
Deferred Reserves	Established natural gas reserves which are not currently available to a market for a specific reason, usually their involvement in efficient recovery of oil or LPG.
Electric Arc Technology	Use of electrical arcs in a furnace to efficiently produce very high temperatures for applications such as metal melting and coating and industrial drying.
Electricity Production	The process of generating electric energy. In this report it includes the amount of such energy, expressed in kilowatt hours or multiples of kilowatt hours, that individual generating units or groups of generating units can reasonably be expected to produce in a year. The determination of electric energy production takes into account various factors such as the type of service for which generating units were designed (e.g., peaking or base load) the availability of fuels, the cost of fuels, river water levels, and environmental constraints.
End Use Demand for Energy (or Secondary Energy Demand)	Energy used by final consumers for residential, commercial, industrial and transportation purposes, and hydrocarbons used for such non-energy purposes as petrochemical feedstock.
Energy Intensity	In the industrial and commercial sectors and in transportation other than automobiles energy intensity is defined as the amount of energy per unit of production. In the residential sector it is energy use per household and for automobiles it is energy use per car. A measure of the efficiency with which energy is used in the economy as a whole is total end use energy per unit of GNP.
Enhanced Oil Recovery (or Enhanced Recovery)	See 'Recovery - Enhanced'
Established Reserves	Those (oil and gas) reserves recoverable under current technology and present and anticipated economic conditions, specifically proved by drilling, testing or production, plus that judgment portion of contiguous recoverable reserves that is interpreted to exist, from geological, geophysical or similar information, with reasonable certainty.
Experimental Crude Oil	Crude oil produced from pilot projects designed to investigate new recovery techniques.
Export of Electricity	Transfer of power or energy from a utility system in Canada to another in the United States. Such export requires NEB approval.
Feedstock	Raw material supplied to a refinery or petrochemical plant.
Firm Power	Electric power intended to be available at all times during the period covered by an agreement.
Flat Life	That period of the producing life of a resource during which production is maintained at a constant rate.
Frontier Areas	Generally, the northern and offshore areas of Canada.

Fuel Efficiency (Burner Tip Efficiency)	The ratio of the useful output energy which results when a fuel is burned, to the theoretical input energy content of the fuel. Fuel efficiency for a heating fuel is less than 100 percent to the extent that heated air is used in combustion and to the extent that exhaust venting is necessary. In other applications fuel efficiencies are less than 100 percent partly because of waste heat generation.
Gas Cycling Scheme	A scheme in which part or all of the produced natural gas is reinjected into the reservoir after removal of natural gas liquids.
Heavy Crude Oil	A term applied to crude oil having a high density. Appendix A6-3 shows production from the crude streams which are included in the NEB's heavy crude category.
Heavy Fuel Oil	In this report the term heavy fuel oil is used to include bunker fuel oils (No. 5 and No. 6 fuel oils) and industrial fuel oil (No. 4 fuel oil).
High (Oil) Price Case	See Chapter 2, Table 2-2 and Figure 2-1.
Hog Fuel	Fuel consisting of bark, shavings, sawdust, low grade lumber and lumber rejects from the operation of pulp mills, sawmills and plywood mills.
Hybrid System	A dual fuel heating system using two alternative sources of energy. The most common systems use oil and electricity.
Hydroelectric Generation	An electric generator driven by a hydraulic turbine.
Infill Drilling	The process of drilling additional wells within the defined pool outline of a natural gas or oil pool.
Initial Established Reserves	Established reserves prior to the deduction of any production.
In Situ Recovery	The process of recovering crude bitumen from oil sands other than by surface mining.
Interruptible Power	Electric power and/or energy made available under an agreement that permits curtailment or cessation of availability at the option of the supplier.
Light Crude Oil	A term applied to crude oil having a low density. Appendix A6-14 shows production from the crude streams which are included in the NEB's light crude category.
Light Fuel Oil	In this report the term light fuel refers to furnace fuel oil (No. 2 fuel oil), kerosene and stove oil (No. 1 fuel oil). The major volume of light fuel oil used in Canada is furnace fuel oil.
Liquefied Petroleum Gases (LPG)	As used in this report, the term refers to the hydrocarbons propane and butanes, or combinations thereof.
Load Factor	The ratio of the average load over a designated period of time to the maximum load occurring in that period, expressed in percent.
Low (Oil) Price Case	See Chapter 2, Table 2-2 and Figure 2-1.
Marketable Natural Gas	Natural gas which meets specifications for end use.
Middle Distillates	The range of refined petroleum products which includes kerosene, stove oil, diesel fuel, and light fuel oil.

Table A1-3 (Continued)
Definitions

Miscible Flooding	An enhanced recovery process in which a fluid, capable of mixing completely with the oil it contacts, is injected into an oil reservoir to increase recovery.
Natural Gas Liquids (NGL)	The hydrocarbons, ethane, propane, butanes, and pentanes plus or a combination thereof.
Non-Associated Gas	Natural gas not in contact with crude oil in the reservoir.
Non-Conventional Generation	The generation of electricity by any means other than hydroelectric generation, thermal generation using nuclear fuel, coal, oil or natural gas, gas turbine generation using oil and natural gas, or internal combustion generation. Examples would be solar power and wind energy.
Oil Sands	Deposits of sand or sandstone, or other sedimentary rocks containing crude bitumen.
Peak Demand (Electricity)	The highest level of power demand by customers on a power system within a specified period, usually a year, (i.e., on a major utility, a minor utility or an individual industry generating its own electricity). The peak demand is measured in kilowatts or multiples of kilowatts.
Peaking Capacity	Electricity generating equipment which is available to meet that portion of the load which occurs for only a few hours during the day.
Pentanes Plus	A liquid by-product of natural gas production which is composed primarily of pentanes and heavier hydrocarbons.
Permeability	A measure of the capacity of a reservoir rock to transmit fluids.
Petroleum Incentives Program	A government program of grants to encourage petroleum exploration and development.
Plasma Arc Technology	Use of electrical arcs in a plasma furnace to efficiently produce very high temperatures for applications such as metal melting and coating, and industrial drying.
Primary Energy Demand	Represents the total requirement for all uses of energy in Canada, including energy used by the final consumer, intermediate uses of energy in transforming one energy form to another (e.g. coal to electricity), and energy used by suppliers in providing energy to the market (e.g. pipeline fuel). By definition: Primary energy demand = end use energy demand + energy supply industry use - electricity and steam demand + energy used to generate electricity and produce steam + other conversion losses
Primary Recovery	See 'Recovery - Primary'

Productive Capacity	The estimated rate at which natural gas, crude oil or crude bitumen can be produced from a well, pool or other entity, unrestricted by demand, having regard to reservoir characteristics, economic considerations, regulatory limitations, the feasibility of infill drilling and/or additional production facilities, the availability of gathering, processing and transmission facilities, and potential losses due to mechanical breakdown.
Pulping Liquor (also known as waste liquor or black liquor)	A substance primarily made up of lignin, other wood constituents, and chemicals which are by-products of the manufacture of chemical pulp. It can be burned in a boiler to produce steam or electricity, through thermal generation.
Rate of Take	The average daily rate of production of natural gas related to the volume of initial established reserves assigned to the reservoir or reservoirs from which the production is obtained. For example, 1:7300 means one unit of production a day for each 7 300 units of initial established reserves.
Raw Natural Gas	Unprocessed natural gas.
Recovery - Primary	The volume of crude oil recoverable from a reservoir through natural depletion processes only.
- Secondary	The incremental volume of crude oil recoverable from a reservoir through the utilization of a pressure maintenance scheme such as waterflooding or gas injection.
- Tertiary	The incremental volume of crude oil recoverable from a reservoir other than through natural depletion and pressure maintenance processes.
- Enhanced	The incremental volume of crude oil recoverable from a reservoir through a production process other than natural depletion; the production process used to achieve such incremental volume. Enhanced recovery includes both secondary and tertiary recovery.
Refinery Acquisition Cost	The delivered price of crude oil to a refinery, including all transportation charges to that point.
Remaining Capacity (Electricity)	The difference between Capacity Available and the System Peak Demand. The remaining capacity includes the margin of capability available to provide for scheduled maintenance, emergency outages, system operating requirements and unforeseen loads. On a national basis it is the difference between the aggregate net Capacity Available of the various systems in Canada and the sum of the System Peak Demands, without allowance for time diversity between the loads of the several systems.
Remaining Established Reserves	Initial established reserves less cumulative production.
Reserves Additions	Incremental changes to established reserves resulting from the discovery of new pools and reserves appreciation.
Reserves Appreciation	Incremental change in established reserves resulting from extensions to existing pools and/or revisions to previous reserves estimates.
Reserves Life Index	Remaining reserves divided by annual production.

Table A1-3 (Continued)
Definitions

Retrofitting	
- A house:	upgrading an existing house to reduce heat loss. Retrofitting includes measures such as adding insultation, caulking, weatherstripping and adding or improving storm windows and doors.
- A heating system:	replacing selected system components to increase efficiency while retaining most of the original system.
R-2000 homes	Type of new super efficient homes which are expected to meet the standard building code of the year 2000.
Secondary Recovery	See 'Recovery - Secondary'
Shut-in Capacity	The unused productive capacity of an oil or gas pool or area.
Social Supply Cost	The sum of capital and operating costs per unit of production, exclusive of royalties, taxes, subsidies, or incentive payments, discounted at the estimated social opportunity cost of capital in Canada.
Solar Energy - Active System	Solar energy collection systems which transfer heat captured from solar radiation through mechanical devices.
Solar Energy - Passive System	Solar energy collection systems which capture solar radiation directly for space heating, water heating or other similar purposes, without the use of mechanical devices.
Solution Gas	Natural gas in solution with crude oil in the reservoir at original reservoir conditions and which is normally produced with the crude oil.
Solvent Flooding	See 'Miscible Flooding'
Straddle Plant	A natural gas processing plant, located on a main gas transmission system, which extracts NGL from the gas stream.
Synthetic Crude Oil	Crude oil resulting from the processing of crude bitumen.
Synthetic Natural Gas (SNG)	Natural gas produced from petroleum liquids, coal or wood.
Tertiary Recovery	See 'Recovery - Tertiary'
Thermal Generation	Energy conversion in which fuel is consumed to generate heat energy which is converted to mechanical energy and then to electricity in a generator. Normally, the fuel may be coal, oil, gas, or uranium (nuclear).
Thermal Processes	Enhanced oil recovery processes in which heat is added to the reservoir to increase recovery.
Thermo-Mechanical Pulping Process (TMP)	A process used in the pulp and paper industry. Electrically produced mechanical energy is used to steam and refine wood chips into pulp. The steaming process softens the wood chips with the result that the pulp produced is of a higher quality than that obtained from other processes. Recovered steam may be used for space heating or for drying pulp fibres.
Transfer Capability	The overall capacity of interprovincial or international power lines, together with the associated electrical system facilities, to transfer power and energy from one electrical system to another.
Transmission	The movement or transfer of electricity from one point to another in a power system and between systems.

Ultimate Potential	An estimate of the initial established reserves which will have become developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of the area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves and future additions through extensions and revisions to existing pools and the discovery of new pools.
Waterflooding	An enhanced recovery process in which water is injected into an oil reservoir to increase recovery.
Wellhead	Specifically, the equipment at the top of a well for maintaining control of the well. More generally, it is used to specify a reference or delivery point on the production system.
World Oil Price	As used in this report, the term refers to the official selling price of West Texas Intermediate crude oil at Chicago.
Wood Gasification	The production of a synthetic natural gas from wood.
Wood Liquefaction	The production of liquids (e.g. methanol) from wood.
Wood Waste	Fuel consisting of bark, shavings, sawdust and low grade lumber and lumber rejects from the operation of pulp mills, sawmills and plywood mills.
Wood Wastes	Refers to wood waste and pulping liquor.

Appendix 2

Table A2-1
World Oil Prices

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
($U.S. 1986 / Barrel)										
Low Price Case	31.23	28.80	14.00	14.00	14.00	15.00	16.00	18.00	18.00	18.00
High Price Case	31.23	28.80	16.00	17.00	18.00	20.00	22.00	27.00	27.00	27.00
($C 1986 / Cubic Metre)										
Low Price Case	259.04	250.16	124.22	123.72	121.98	131.20	140.05	153.09	150.81	150.90
High Price Case	259.04	250.16	141.96	149.08	155.04	170.95	187.39	220.38	216.85	217.14

Note: West Texas Intermediate at Chicago

Table A2-2
Real Gross Domestic Product Growth Rates - Canada and Regions

(Percent per Annum)	1984-1990	1990-1995	1995-2000	2000-2005
Atlantic Canada				
Low Price Case	2.1	1.5	2.6	2.8
High Price Case	2.2	1.6	2.4	2.4
Newfoundland				
Low Price Case	2.1	-1.0	3.2	3.0
High Price Case	3.6	0.7	3.4	2.7
Prince Edward Island				
Low Price Case	2.1	2.3	2.5	2.6
High Price Case	1.7	2.1	2.3	2.3
Nova Scotia				
Low Price Case	1.3	2.2	2.3	2.6
High Price Case	0.9	1.9	2.0	2.3
New Brunswick				
Low Price Case	3.2	2.2	2.5	2.8
High Price Case	2.8	1.8	2.2	2.4
Central Canada				
Low Price Case	3.7	2.5	2.5	3.1
High Price Case	3.1	2.1	2.2	2.7
Quebec				
Low Price Case	3.3	2.4	2.4	2.9
High Price Case	2.8	2.1	2.1	2.5
Ontario				
Low Price Case	4.0	2.6	2.5	3.2
High Price Case	3.3	2.2	2.2	2.8
Prairies				
Low Price Case	2.2	3.1	2.5	2.6
High Price Case	2.8	3.3	2.4	2.3
Manitoba				
Low Price Case	3.4	3.3	2.7	3.0
High Price Case	3.2	3.1	2.3	2.5
Saskatchewan				
Low Price Case	4.3	2.2	3.1	2.7
High Price Case	4.1	2.0	2.8	2.3
Alberta				
Low Price Case	0.8	3.3	2.2	2.3
High Price Case	2.1	4.0	2.2	2.3
B.C. and Territories				
Low Price Case	3.0	2.3	2.5	2.6
High Price Case	2.5	1.9	2.2	2.1
Canada				
Low Price Case	3.3	2.5	2.5	2.9
High Price Case	2.9	2.3	2.2	2.5

Appendix 3

Table A3-1

Historical Data - Total Energy Demand - End Use by Sector - Primary Demand by Fuel

Canada

(Petajoules)	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Sectoral Demand										
Residential	1001.4	1002.2	1035.5	1073.4	1116.2	1161.1	1175.7	1249.9	1211.6	1298.5
Commercial	416.9	468.1	512.1	575.7	631.1	667.0	703.6	799.5	762.0	797.5
Industrial	1152.1	1207.3	1267.1	1333.8	1391.0	1459.2	1479.4	1560.7	1681.9	1761.5
Transportation - Road	732.4	779.4	822.0	879.0	918.2	970.8	1006.5	1079.0	1181.3	1235.7
- Air, Rail, Marine	257.1	274.6	286.3	286.4	290.2	303.8	312.9	333.6	359.4	365.8
- Total	989.5	1054.0	1108.3	1165.4	1208.4	1274.5	1319.5	1412.6	1540.7	1601.4
Non-Energy [a]	215.0	237.6	244.8	253.8	282.0	339.7	346.7	368.6	414.0	413.9
Total End Use	3775.0	3969.3	4167.9	4402.1	4628.8	4901.4	5024.8	5391.2	5610.2	5872.8
Own Use	214.5	222.7	232.5	243.3	246.8	350.8	374.1	411.7	444.0	460.8
Electricity and Steam Generation [b] [d]	682.1	739.1	798.0	903.3	942.3	1101.3	1187.3	1290.7	1443.6	1501.3
Other Conversions	184.3	189.4	182.5	212.4	190.7	224.0	207.4	210.3	240.3	236.2
Less Electricity, Steam, Coke and Coke Oven Gas	672.8	720.4	748.5	812.7	840.1	915.9	938.4	1015.5	1103.0	1167.4
Primary Energy Demand	4183.0	4400.1	4632.5	4948.3	5168.5	5661.6	5855.1	6288.5	6635.2	6903.7
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	1.5	1.9	1.7	10.4	6.0	11.8	47.2	74.3	173.2	168.5
Hydro [b]	415.4	458.5	470.2	478.4	527.2	555.7	567.8	631.9	660.9	734.5
Oil	2395.5	2517.0	2710.3	2886.5	3016.9	3247.3	3309.1	3516.8	3665.1	3763.7
Natural Gas	613.1	675.0	729.3	809.3	885.3	1064.9	1175.5	1359.2	1435.3	1524.5
NGL-Gas Plant	45.7	56.5	37.4	39.5	45.8	39.3	45.3	53.9	58.9	73.4
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	622.9	608.5	602.0	646.1	614.9	674.0	647.6	595.7	584.5	580.7
Renewables	88.9	82.6	81.5	78.1	72.5	68.7	62.6	56.6	57.3	58.4

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A3-1 (Continued)
Historical Data - Total Energy Demand - End Use by Sector - Primary Demand by Fuel
Canada

(Petajoules)	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Sectoral Demand										
Residential	1288.4	1304.6	1261.7	1341.4	1352.5	1365.4	1297.3	1349.0	1308.4	1302.0
Commercial	754.5	850.1	844.8	840.5	850.5	819.7	838.1	866.7	858.5	872.3
Industrial	1651.1	1979.7	2076.8	2157.8	2260.9	2287.1	2168.7	1981.1	1978.3	2104.1
Transportation - Road	1286.2	1361.7	1406.3	1450.3	1523.0	1544.6	1505.7	1397.2	1363.1	1397.7
- Air, Rail, Marine	338.1	329.7	330.9	349.0	403.1	417.2	406.6	347.5	314.7	327.0
- Total	1624.3	1691.4	1737.2	1799.4	1926.1	1961.8	1912.2	1744.7	1677.8	1724.7
Non-Energy [a]	410.6	461.0	545.0	571.0	647.9	625.2	606.7	549.6	599.5	674.6
Total End Use	5728.8	6286.8	6465.4	6710.1	7038.1	7059.4	6823.0	6491.1	6422.5	6677.7
Own Use	469.8	475.7	482.4	509.3	521.4	516.3	488.3	466.2	453.0	479.4
Electricity and Steam Generation [b] [d]	1525.0	1611.7	1739.7	1830.0	1969.0	2101.4	2154.0	2194.4	2296.8	2467.8
Other Conversions	222.2	233.2	214.2	222.4	251.1	234.4	210.1	182.5	183.1	211.2
Less Electricity, Steam, Coke and Coke Oven Gas	1158.3	1227.1	1266.9	1334.6	1415.6	1463.9	1471.8	1464.0	1517.0	1627.4
Primary Energy Demand	6787.4	7380.2	7634.8	7937.2	8364.0	8447.6	8203.6	7870.2	7838.4	8208.6
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	144.2	199.7	301.7	357.7	429.0	457.8	490.6	475.3	565.9	605.3
Hydro [b]	707.6	748.1	768.4	815.0	833.0	859.2	867.5	855.4	866.6	929.3
Oil	3666.0	3789.5	3816.2	3911.8	4069.8	3976.8	3720.8	3318.0	3086.6	3056.1
Natural Gas	1530.5	1599.4	1684.7	1735.6	1799.7	1776.0	1738.4	1776.6	1813.1	1949.3
NGL-Gas Plant	74.3	66.6	60.9	34.5	43.3	58.3	56.7	56.7	59.0	85.9
Ethane	0.0	2.6	2.6	2.6	13.5	25.3	34.5	22.2	34.6	54.4
Coal	602.3	654.6	681.1	685.3	763.5	823.7	842.3	895.9	925.5	1048.7
Renewables	62.6	319.7	319.2	394.6	412.0	470.4	452.8	470.0	487.1	479.7

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A3-2
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)	Canada									
	Low Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sectoral Demand										
Residential	1302.0	1328.6	1347.5	1368.8	1395.7	1417.1	1430.8	1485.2	1561.0	1648.0
Commercial	872.3	887.5	919.4	954.5	984.6	1006.8	1021.4	1122.2	1254.1	1420.1
Industrial	2104.1	2189.8	2291.8	2380.2	2457.9	2536.2	2553.0	2802.0	3126.7	3628.7
Transportation - Road	1397.7	1407.0	1412.7	1418.5	1428.6	1442.0	1459.3	1558.6	1676.1	1789.6
- Air, Rail, Marine	327.0	324.6	342.0	358.7	369.8	374.6	371.7	407.2	446.4	489.5
- Total	1724.7	1731.7	1754.7	1777.3	1798.4	1816.7	1831.0	1965.7	2122.5	2279.1
Non-Energy [a]	674.6	748.2	770.1	790.5	790.3	804.1	817.8	880.9	959.9	1006.7
Total End Use	6677.7	6885.8	7083.5	7271.3	7426.9	7581.0	7654.0	8256.1	9024.2	9982.5
Own Use	479.4	500.0	514.3	534.4	556.7	581.5	582.2	595.6	621.0	691.1
Electricity and Steam Generation [b] [d]	2467.8	2551.2	2687.1	2808.2	2928.0	2999.1	3079.5	3522.8	4006.8	4681.2
Other Conversions	211.2	234.1	252.8	266.7	274.0	282.1	278.5	301.6	331.4	382.5
Less Electricity, Steam, Coke and Coke Oven Gas	1627.4	1710.4	1790.4	1842.1	1889.9	1901.3	1926.2	2156.8	2429.9	2791.2
Primary Energy Demand	8208.6	8460.7	8747.3	9038.4	9295.6	9542.5	9668.0	10519.2	11553.5	12946.1
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	605.3	714.5	804.8	917.6	1067.1	1135.2	1199.3	1339.0	1364.8	1532.2
Hydro [b]	929.3	976.9	1012.8	1032.4	1047.8	1025.0	1037.7	1150.5	1278.2	1422.4
Oil	3056.1	3061.0	3126.9	3157.8	3170.3	3218.2	3193.6	3292.3	3477.6	3787.1
Natural Gas	1949.3	2055.8	2078.1	2179.2	2288.4	2398.9	2438.1	2648.7	2914.4	3301.8
NGL-Gas Plant	85.9	83.6	87.8	98.6	108.1	114.4	120.7	129.2	135.4	140.4
Ethane	54.4	72.0	76.0	80.0	80.4	80.8	81.2	99.6	126.3	126.3
Coal	1048.7	980.2	1031.4	1030.5	983.7	1010.2	1031.1	1256.6	1616.4	1966.3
Renewables	479.7	516.8	529.5	542.2	549.7	559.8	566.3	603.3	640.4	669.6

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A3-2 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)	Canada									
	High Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sectoral Demand										
Residential	1302.0	1328.6	1340.6	1353.0	1364.7	1372.1	1373.3	1381.5	1443.7	1523.2
Commercial	872.3	887.5	917.4	941.4	959.7	970.9	975.8	1036.1	1141.3	1269.5
Industrial	2104.1	2189.8	2290.8	2343.2	2391.5	2444.3	2445.2	2617.2	2872.8	3277.0
Transportation - Road	1397.7	1407.0	1410.4	1412.2	1416.4	1422.8	1430.1	1466.4	1522.7	1577.6
- Air, Rail, Marine	327.0	324.6	336.3	347.6	353.3	354.6	349.4	365.2	388.4	416.6
- Total	1724.7	1731.7	1746.7	1759.8	1769.7	1777.4	1779.5	1831.6	1911.1	1994.2
Non-Energy [a]	674.6	748.2	769.6	789.0	786.6	800.4	813.9	875.5	951.3	993.2
Total End Use	6677.7	6885.8	7065.1	7186.4	7272.2	7365.1	7387.7	7742.0	8320.2	9057.1
Own Use	479.4	500.0	512.9	528.4	545.6	565.9	562.8	555.9	567.0	614.5
Electricity and Steam Generation [b] [d]	2467.8	2551.2	2677.4	2788.8	2895.8	2952.6	3044.0	3514.2	3956.1	4580.7
Other Conversions	211.2	234.1	251.2	260.3	266.5	273.8	269.4	284.9	305.3	342.3
Less Electricity, Steam, Coke and Coke Oven Gas	1627.4	1710.4	1788.7	1826.6	1865.9	1873.2	1897.7	2116.6	2373.0	2692.0
Primary Energy Demand	8208.6	8460.7	8718.0	8937.4	9114.2	9284.2	9366.3	9980.3	10775.6	11902.6
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	605.3	714.5	807.2	918.0	1063.6	1128.1	1187.4	1324.5	1357.6	1603.4
Hydro [b]	929.3	976.9	1009.5	1022.2	1036.1	1018.0	1022.0	1125.1	1252.0	1387.8
Oil	3056.1	3061.0	3102.0	3114.0	3096.8	3121.1	3076.0	3005.2	3074.8	3213.8
Natural Gas	1949.3	2055.8	2086.4	2155.8	2231.5	2304.9	2319.4	2425.3	2622.7	2918.0
NGL-Gas Plant	85.9	83.6	89.7	100.9	110.8	117.6	124.2	135.1	144.3	152.7
Ethane	54.4	72.0	76.0	80.0	80.4	80.8	81.2	99.6	126.3	126.3
Coal	1048.7	980.2	1017.7	1004.4	946.2	955.5	991.7	1265.0	1560.6	1833.8
Renewables	479.7	516.8	529.6	542.0	548.9	558.4	564.4	600.4	637.4	666.8

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A3-2 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)	Atlantic									
	Low Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sectoral Demand										
Residential	105.8	108.0	108.7	110.1	110.8	112.4	113.5	118.1	123.2	131.9
Commercial	60.7	58.6	60.6	63.1	64.0	64.6	65.2	70.3	77.6	86.7
Industrial	154.1	151.2	156.8	160.5	162.9	165.4	167.8	167.4	179.8	205.2
Transportation - Road	116.2	115.2	115.8	116.1	116.5	116.9	117.7	122.4	130.9	141.4
- Air, Rail, Marine	40.8	41.0	43.9	46.1	47.6	47.9	47.1	51.9	57.6	64.3
- Total	156.9	156.3	159.7	162.2	164.0	164.9	164.7	174.3	188.5	205.7
Non-Energy [a]	14.5	15.8	16.3	16.7	17.2	17.5	17.6	19.0	20.9	23.2
Total End Use	491.9	489.9	502.1	512.6	519.0	524.8	528.9	549.2	589.9	652.7
Own Use	29.8	30.4	31.3	32.3	33.1	33.9	32.9	35.5	37.8	42.4
Electricity and Steam Generation [b] [d]	316.6	336.2	361.4	366.7	375.7	384.0	402.7	481.2	573.7	657.0
Other Conversions	0.0	5.6	6.1	6.4	6.5	6.7	6.6	7.2	7.9	9.0
Less Electricity, Steam, Coke and Coke Oven Gas	114.7	115.2	115.8	119.0	120.9	123.9	126.9	144.6	166.9	198.9
Primary Energy Demand	723.6	746.9	785.1	799.0	813.4	825.4	844.2	928.5	1042.4	1162.3
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	33.9	45.3	34.1	34.1	34.1	34.1	34.1	34.1	34.1	34.1
Hydro [b]	171.7	139.7	159.4	159.7	159.8	160.0	160.6	176.9	207.6	208.4
Oil	373.5	395.8	409.2	418.2	431.6	441.6	415.5	401.0	408.3	444.8
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2
NGL-Gas Plant	1.9	1.6	1.6	1.6	1.6	1.6	1.9	2.4	3.0	3.2
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	75.3	96.4	111.8	114.8	114.9	115.7	158.7	238.0	310.0	389.0
Renewables	67.3	68.1	69.0	70.5	71.5	72.5	73.4	76.1	79.3	82.6

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A3-2 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules) — Atlantic — High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sectoral Demand										
Residential	105.8	108.0	108.2	109.0	109.1	110.3	111.0	113.8	120.2	129.0
Commercial	60.7	58.6	60.3	62.4	63.1	63.5	63.9	67.5	74.2	81.7
Industrial	154.1	151.2	157.1	160.5	164.0	166.9	170.3	169.8	185.5	210.5
Transportation - Road	116.2	115.2	115.6	115.6	115.6	115.6	115.7	117.1	122.9	129.1
- Air, Rail, Marine	40.8	41.0	43.1	44.6	45.2	45.1	43.9	46.2	50.2	54.9
- Total	156.9	156.3	158.8	160.2	160.8	160.7	159.6	163.3	173.1	183.9
Non-Energy [a]	14.5	15.8	16.3	16.6	17.0	17.3	17.5	18.9	20.5	22.5
Total End Use	491.9	489.9	500.6	508.8	514.1	518.7	522.2	533.2	573.4	627.7
Own Use	29.8	30.4	31.3	32.3	33.1	34.0	33.2	34.4	37.3	41.8
Electricity and Steam Generation [b] [d]	316.6	336.2	362.7	371.2	378.6	389.3	412.9	480.5	547.7	626.2
Other Conversions	0.0	5.6	6.1	6.3	6.4	6.5	6.4	6.8	7.3	8.1
Less Electricity, Steam, Coke and Coke Oven Gas	114.7	115.2	116.0	119.0	121.6	125.2	129.0	146.8	172.6	203.0
Primary Energy Demand	723.6	746.9	784.7	799.6	810.5	823.3	845.7	908.2	993.1	1100.8
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	33.9	45.3	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8
Hydro [b]	171.7	139.7	159.0	159.4	159.6	159.6	159.6	190.4	207.3	207.3
Oil	373.5	395.8	408.1	418.5	428.5	439.3	418.0	369.3	384.6	419.0
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2
NGL-Gas Plant	1.9	1.6	2.3	2.4	2.4	2.5	2.8	3.6	4.3	4.8
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	75.3	96.4	109.6	112.1	112.0	113.0	155.5	231.3	277.8	345.4
Renewables	67.3	68.1	68.9	70.3	71.1	72.1	73.0	76.8	82.2	87.5

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

(Petajoules) **Quebec**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sectoral Demand										
Residential	285.2	293.0	297.9	302.2	310.0	315.8	319.2	326.8	336.6	348.2
Commercial	169.3	170.7	175.7	182.5	187.9	192.7	195.9	215.2	236.8	265.9
Industrial	488.0	501.9	526.0	539.8	552.9	579.3	583.9	636.4	708.0	819.3
Transportation - Road	281.8	285.1	284.8	284.8	286.1	288.7	292.6	318.8	342.8	359.5
- Air, Rail, Marine	73.9	69.4	73.9	77.5	79.8	80.6	79.5	88.1	97.8	108.5
- Total	355.7	354.5	358.6	362.3	365.9	369.3	372.1	406.9	440.6	468.0
Non-Energy [a]	83.0	85.2	87.6	89.8	92.1	96.7	100.7	109.5	116.1	124.4
Total End Use	1381.2	1405.4	1445.8	1476.5	1508.8	1553.7	1571.8	1694.8	1838.1	2026.0
Own Use	96.1	97.8	102.0	103.8	104.4	104.6	104.5	112.7	122.0	134.9
Electricity and Steam Generation [b] [d]	430.4	488.0	501.7	516.0	526.6	500.3	510.1	574.0	637.4	756.8
Other Conversions	0.0	3.7	4.0	4.2	4.3	4.4	4.3	4.7	5.2	5.9
Less Electricity, Steam, Coke and Coke Oven Gas	490.3	525.7	549.3	563.6	577.6	558.5	571.7	648.1	730.5	835.0
Primary Energy Demand	1417.4	1469.2	1504.2	1536.9	1566.4	1604.5	1619.0	1738.0	1872.2	2088.6
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	41.4	39.0	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7
Hydro [b]	386.5	446.5	445.3	459.6	469.9	443.2	453.0	516.2	577.2	684.9
Oil	722.0	677.5	691.4	696.9	698.3	720.0	713.7	728.4	760.7	818.5
Natural Gas	162.4	188.6	191.7	201.8	216.7	254.5	261.5	295.5	329.7	375.2
NGL-Gas Plant	4.1	5.6	7.1	7.7	8.2	10.7	13.3	15.1	15.7	16.1
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	14.3	22.1	23.0	23.3	23.5	23.9	23.6	23.5	23.5	24.2
Renewables	86.8	89.9	91.9	93.8	96.2	98.5	100.3	105.6	111.6	116.0

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A3-2 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules) — Quebec — High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sectoral Demand										
Residential	285.2	293.0	297.1	299.7	305.6	309.3	310.8	311.7	320.1	331.1
Commercial	169.3	170.7	175.3	180.6	184.0	186.9	188.2	200.1	217.4	239.8
Industrial	488.0	501.9	523.6	528.7	533.8	550.6	548.6	575.8	627.5	715.8
Transportation - Road	281.8	285.1	284.5	283.7	283.7	284.6	285.7	294.8	304.2	310.6
- Air, Rail, Marine	73.9	69.4	72.6	75.0	76.2	76.1	74.5	78.6	84.9	91.9
- Total	355.7	354.5	357.0	358.8	359.9	360.7	360.2	373.4	389.1	402.6
Non-Energy [a]	83.0	85.2	87.5	89.5	91.4	96.1	100.2	108.9	115.0	122.4
Total End Use	1381.2	1405.4	1440.6	1457.3	1474.7	1503.6	1507.9	1569.9	1669.1	1811.7
Own Use	96.1	97.8	101.5	102.5	102.3	101.7	100.8	105.4	111.8	121.0
Electricity and Steam Generation [b] [d]	430.4	488.0	500.5	510.7	522.0	501.2	502.8	555.8	628.7	732.1
Other Conversions	0.0	3.7	4.0	4.1	4.2	4.2	4.2	4.4	4.8	5.3
Less Electricity, Steam, Coke and Coke Oven Gas	490.3	525.7	548.1	558.2	569.3	548.4	560.6	632.9	710.4	804.0
Primary Energy Demand	1417.4	1469.2	1498.5	1516.4	1533.9	1562.3	1555.0	1602.6	1704.0	1866.1
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	41.4	39.0	53.7	53.7	53.7	53.7	53.7	53.7	53.7	53.7
Hydro [b]	386.5	446.5	444.1	454.3	465.3	444.1	445.7	498.0	570.7	673.6
Oil	722.0	677.5	684.0	684.2	678.3	691.7	676.5	650.4	650.4	670.4
Natural Gas	162.4	188.6	193.5	198.6	208.3	239.7	242.1	257.1	279.4	313.2
NGL-Gas Plant	4.1	5.6	8.2	8.8	9.4	11.9	14.6	16.9	18.0	19.0
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	14.3	22.1	22.9	22.8	22.6	22.7	22.2	21.3	20.9	21.2
Renewables	86.8	89.9	92.1	93.9	96.2	98.5	100.2	105.1	110.9	115.0

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

(Petajoules) **Ontario**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sectoral Demand										
Residential	460.4	461.7	472.9	483.1	498.5	507.0	512.6	541.2	569.6	603.3
Commercial	341.0	341.2	359.9	376.1	391.1	402.6	410.3	453.6	508.8	581.2
Industrial	797.7	825.4	876.8	930.0	979.1	1013.3	1011.9	1121.2	1264.0	1496.7
Transportation - Road	498.3	506.1	514.1	523.0	534.3	547.2	561.2	622.6	670.2	709.9
- Air, Rail, Marine	90.1	86.8	90.8	94.9	97.6	98.8	98.2	106.6	115.3	126.0
- Total	588.4	592.9	604.9	617.9	631.9	646.0	659.4	729.1	785.4	835.9
Non-Energy [a]	207.1	233.0	238.7	235.9	225.1	230.1	234.2	248.5	264.5	276.7
Total End Use	2394.5	2454.2	2553.3	2642.8	2725.8	2798.9	2828.5	3093.6	3392.3	3793.9
Own Use	179.6	189.2	195.6	203.3	211.7	222.3	224.4	240.0	251.8	280.3
Electricity and Steam Generation [b] [d]	975.3	975.1	1082.5	1174.6	1265.1	1337.7	1375.9	1568.3	1779.9	2117.1
Other Conversions	200.3	209.5	228.3	239.5	245.6	251.4	248.0	271.9	303.2	350.1
Less Electricity, Steam, Coke and Coke Oven Gas	643.3	673.1	711.2	740.3	766.3	786.2	787.7	876.3	984.7	1140.7
Primary Energy Demand	3106.4	3155.0	3348.5	3520.0	3681.9	3824.1	3889.1	4297.6	4742.4	5400.6
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	530.0	630.2	717.1	829.8	979.3	1047.4	1111.5	1251.2	1277.1	1444.5
Hydro [b]	147.0	149.1	144.3	144.3	144.3	144.3	144.3	157.5	157.9	158.2
Oil	1036.3	1041.3	1069.8	1079.8	1074.1	1089.2	1100.3	1170.4	1247.0	1372.3
Natural Gas	767.8	788.3	821.0	867.0	925.3	967.6	981.7	1091.9	1207.4	1382.8
NGL-Gas Plant	32.2	34.2	37.3	47.4	56.5	60.3	63.5	67.3	69.1	70.5
Ethane	4.8	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Coal	500.7	417.9	463.1	453.6	401.7	412.4	382.2	445.7	658.9	837.2
Renewables	87.6	89.6	91.7	93.8	96.4	98.5	101.2	109.3	120.8	130.8

Notes:[a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A3-2 (Continued)

Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)	Ontario									
	High Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sectoral Demand										
Residential	460.4	461.7	471.4	475.8	484.7	486.6	486.0	491.0	513.2	544.4
Commercial	341.0	341.2	358.7	369.4	378.1	383.5	385.7	408.6	449.8	502.8
Industrial	797.7	825.4	871.6	900.6	928.1	946.5	935.7	993.4	1096.5	1279.9
Transportation - Road	498.3	506.1	513.2	520.3	528.4	537.2	545.8	574.4	591.6	604.6
- Air, Rail, Marine	90.1	86.8	89.4	92.3	93.8	94.2	93.0	95.6	99.2	105.6
- Total	588.4	592.9	602.6	612.6	622.3	631.4	638.7	670.0	690.7	710.2
Non-Energy [a]	207.1	233.0	238.3	234.9	223.3	227.9	231.7	244.6	259.1	269.5
Total End Use	2394.5	2454.2	2542.6	2593.4	2636.5	2675.9	2677.9	2807.5	3009.3	3306.8
Own Use	179.6	189.2	194.7	199.9	205.6	213.8	213.6	218.4	221.8	237.8
Electricity and Steam Generation[b] [d]	975.3	975.1	1065.7	1142.9	1214.7	1259.1	1302.9	1508.0	1671.7	1990.7
Other Conversions	200.3	209.5	226.8	234.5	238.5	243.6	240.3	257.1	279.4	313.8
Less Electricity, Steam, Coke and Coke Oven Gas	643.3	673.1	708.8	727.8	746.4	762.0	762.0	834.3	928.5	1063.6
Primary Energy Demand	3106.4	3155.0	3321.1	3443.0	3549.0	3630.3	3672.7	3956.6	4253.7	4785.4
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	530.0	630.2	716.7	827.5	973.1	1037.6	1096.9	1234.1	1267.1	1512.9
Hydro [b]	147.0	149.1	144.3	144.3	144.3	144.3	144.3	144.7	157.9	158.2
Oil	1036.3	1041.3	1057.3	1058.3	1040.6	1043.9	1042.5	1044.7	1059.9	1087.2
Natural Gas	767.8	788.3	821.7	846.5	882.8	905.8	904.6	954.3	1036.6	1172.0
NGL-Gas Plant	32.2	34.2	40.1	50.2	59.4	63.4	66.8	71.2	74.3	77.9
Ethane	4.8	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Coal	500.7	417.9	445.0	418.2	348.8	333.5	313.6	396.5	536.6	646.8
Renewables	87.6	89.6	91.7	93.5	95.7	97.5	99.7	106.8	117.0	126.1

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A3-2 (Continued)

Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)	Manitoba Low Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sectoral Demand										
Residential	57.2	59.4	59.0	60.0	60.7	61.9	63.4	67.3	73.8	79.6
Commercial	41.9	44.4	47.0	49.7	51.4	52.4	52.9	57.6	64.8	73.0
Industrial	36.0	38.5	40.6	44.6	47.3	49.4	50.6	62.0	71.5	84.3
Transportation - Road	63.5	64.1	63.9	63.8	64.0	64.6	65.2	70.8	79.9	87.6
- Air, Rail, Marine	17.7	19.0	19.7	20.5	20.9	21.2	21.2	22.8	24.4	26.3
- Total	81.2	83.1	83.5	84.3	84.9	85.8	86.4	93.6	104.4	113.9
Non-Energy [a]	11.5	11.6	12.1	12.4	12.6	12.8	12.8	13.6	14.4	15.1
Total End Use	227.8	237.0	242.2	251.1	256.8	262.2	266.1	294.1	328.9	365.8
Own Use	24.2	23.7	23.9	25.6	27.9	30.3	29.5	32.0	31.7	35.4
Electricity and Steam Generation [b] [d]	60.9	66.1	67.1	71.6	73.2	75.8	74.3	88.0	97.5	115.1
Other Conversions	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Less Electricity, Steam, Coke and Coke Oven Gas	55.3	57.9	60.5	63.2	64.7	66.0	67.0	78.4	88.6	101.3
Primary Energy Demand	257.5	268.9	272.7	285.2	293.4	302.2	302.9	335.8	369.5	415.1
Primary Energy Demand by Fuel[c] [d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	58.9	60.5	64.4	66.9	68.0	68.7	70.4	82.2	93.2	104.2
Oil	101.8	103.7	104.1	105.1	105.7	106.6	107.1	115.7	128.1	140.2
Natural Gas	81.2	84.0	85.8	91.7	96.9	101.6	102.6	110.8	119.6	132.6
NGL-Gas Plant	2.6	2.4	2.5	2.5	2.5	2.5	2.4	2.7	3.0	3.3
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	3.5	7.2	4.4	6.7	7.3	9.2	6.1	8.6	7.6	15.0
Renewables	9.6	11.1	11.7	12.3	12.9	13.6	14.3	15.8	18.1	19.8

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A3-2 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)	Manitoba									
	High Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sectoral Demand										
Residential	57.2	59.4	58.9	59.4	59.5	60.2	61.2	63.7	69.8	74.7
Commercial	41.9	44.4	46.9	49.0	49.9	50.2	50.3	52.5	57.7	62.9
Industrial	36.0	38.5	40.3	43.4	45.3	46.9	47.6	57.0	64.6	75.0
Transportation - Road	63.5	64.1	63.7	63.6	63.6	63.7	63.9	66.5	71.8	75.9
- Air, Rail, Marine	17.7	19.0	19.4	20.0	20.3	20.4	20.3	21.1	22.0	23.2
- Total	81.2	83.1	83.2	83.6	83.8	84.2	84.3	87.6	93.9	99.1
Non-Energy [a]	11.5	11.6	12.1	12.4	12.5	12.7	12.7	13.5	14.2	14.7
Total End Use	227.8	237.0	241.3	247.7	251.0	254.2	256.1	274.3	300.1	326.5
Own Use	24.2	23.7	23.9	25.3	27.3	29.4	28.4	30.2	29.3	32.3
Electricity and Steam Generation [b] [d]	60.9	66.1	66.9	70.7	72.7	74.4	73.7	87.0	96.2	110.1
Other Conversions	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Less Electricity, Steam, Coke and Coke Oven Gas	55.3	57.9	60.5	62.8	64.0	65.4	66.3	78.1	87.4	98.6
Primary Energy Demand	257.5	268.9	271.7	281.1	287.1	292.6	292.0	313.4	338.2	370.3
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	58.9	60.5	64.4	66.6	67.3	68.4	69.6	82.2	92.2	102.4
Oil	101.8	103.7	102.9	103.3	103.2	103.3	103.1	106.2	113.9	121.0
Natural Gas	81.2	84.0	86.0	90.3	93.7	96.8	96.6	99.4	104.5	113.2
NGL-Gas Plant	2.6	2.4	2.6	2.6	2.6	2.6	2.6	3.0	3.3	3.7
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	3.5	7.2	4.1	6.1	7.4	8.0	6.0	7.2	6.8	11.1
Renewables	9.6	11.1	11.7	12.3	12.9	13.5	14.1	15.5	17.5	19.0

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

(Petajoules) **Saskatchewan**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sectoral Demand										
Residential	76.6	79.1	80.0	80.7	82.1	83.2	84.3	86.8	94.3	101.6
Commercial	35.7	37.5	37.7	38.9	40.2	41.8	43.2	49.4	57.2	66.4
Industrial	76.5	78.9	82.2	87.0	90.1	96.4	101.9	108.3	126.1	143.5
Transportation - Road	82.1	83.0	81.3	79.8	78.4	77.4	76.7	77.3	84.7	94.5
- Air, Rail, Marine	8.6	8.8	9.0	9.2	9.3	9.3	9.2	9.8	10.4	11.1
- Total	90.7	91.7	90.2	89.0	87.7	86.8	85.9	87.1	95.1	105.7
Non-Energy [a]	9.8	11.2	11.5	11.8	12.2	12.5	12.6	13.7	15.2	16.9
Total End Use	289.4	298.3	301.6	307.4	312.4	320.6	327.9	345.3	387.9	434.0
Own Use	41.6	40.3	40.0	43.5	48.6	54.1	53.1	50.6	47.5	53.8
Electricity and Steam Generation [b] [d]	135.7	137.2	126.2	129.0	130.6	136.2	142.3	159.8	195.0	231.6
Other Conversions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Electricity, Steam, Coke and Coke Oven Gas	42.5	42.9	45.0	45.7	46.1	47.6	49.3	54.0	63.3	73.0
Primary Energy Demand	424.0	432.9	422.7	434.2	445.4	463.3	474.1	501.7	567.1	646.3
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	6.1	7.0	13.6	13.6	13.6	13.6	13.6	13.7	13.7	13.8
Oil	140.2	141.7	140.8	139.2	138.0	137.6	136.8	139.1	150.7	165.9
Natural Gas	138.0	139.0	139.8	149.8	160.5	173.4	179.0	185.6	204.7	229.8
NGL-Gas Plant	1.8	2.4	2.2	2.4	2.5	2.7	2.8	2.9	3.1	3.1
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	124.9	129.7	112.9	115.5	117.1	122.0	127.5	145.4	178.9	216.7
Renewables	12.8	13.2	13.5	13.7	13.8	14.0	14.4	15.0	16.0	17.0

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c]Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A3-2 (Continued)

Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules) — Saskatchewan — High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sectoral Demand										
Residential	76.6	79.1	79.6	79.2	79.5	79.5	79.7	78.6	84.8	91.2
Commercial	35.7	37.5	37.6	38.3	39.2	40.3	41.3	45.7	51.9	58.9
Industrial	76.5	78.9	82.5	86.1	89.4	95.2	100.1	104.8	119.9	133.0
Transportation - Road	82.1	83.0	81.1	79.3	77.8	76.5	75.4	73.5	77.4	82.8
- Air, Rail, Marine	8.6	8.8	8.9	9.0	9.0	9.0	8.8	9.1	9.4	9.9
- Total	90.7	91.7	89.9	88.4	86.8	85.5	84.3	82.6	86.8	92.7
Non-Energy [a]	9.8	11.2	11.5	11.8	12.0	12.3	12.5	13.6	14.9	16.4
Total End Use	289.4	298.3	301.2	303.8	307.0	312.8	317.8	325.4	358.3	392.2
Own Use	41.6	40.3	40.0	43.0	47.6	52.6	51.3	47.0	42.8	47.8
Electricity and Steam Generation [b] [d]	135.7	137.2	126.7	130.0	133.8	141.3	148.5	172.7	209.8	243.5
Other Conversions	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less Electricity, Steam, Coke and Coke Oven Gas	42.5	42.9	45.1	46.0	47.0	48.9	51.0	57.4	67.3	76.2
Primary Energy Demand	424.0	432.9	422.7	430.8	441.4	457.8	466.7	487.6	543.6	607.3
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	6.1	7.0	13.6	13.6	13.6	13.6	13.6	13.7	13.7	13.8
Oil	140.2	141.7	139.5	137.3	135.4	134.3	132.9	130.6	136.3	144.7
Natural Gas	138.0	139.0	140.4	147.6	156.2	167.0	170.7	166.0	179.4	201.8
NGL-Gas Plant	1.8	2.4	2.2	2.4	2.5	2.7	2.9	3.0	3.3	3.4
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	124.9	129.7	113.4	116.3	119.8	126.3	132.3	159.5	195.0	226.5
Renewables	12.8	13.2	13.5	13.6	13.8	13.9	14.3	14.9	15.9	17.0

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A3-2 (Continued)

Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
	Alberta									
	Low Price Case									
Sectoral Demand										
Residential	190.5	197.2	197.9	199.7	200.1	200.4	200.7	203.1	213.4	225.3
Commercial	129.4	136.9	139.0	141.5	144.0	144.3	143.6	154.9	172.3	191.2
Industrial	163.7	180.6	175.2	172.3	172.4	173.5	176.0	225.8	258.0	305.2
Transportation - Road	197.5	197.8	197.5	196.4	195.0	193.6	192.6	191.3	201.1	215.1
- Air, Rail, Marine	47.0	50.9	52.5	54.5	55.6	56.3	56.0	60.6	65.4	70.6
- Total	244.5	248.7	250.0	250.9	250.7	249.8	248.6	251.9	266.6	285.7
Non-Energy [a]	313.1	350.4	361.5	376.4	381.5	384.5	389.2	419.8	463.3	481.4
Total End Use	1041.1	1113.8	1123.7	1140.7	1148.7	1152.6	1158.0	1255.5	1373.5	1488.9
Own Use	60.5	65.0	65.7	67.7	69.9	72.2	71.9	69.3	70.0	76.1
Electricity and Steam Generation [b] [d]	376.0	360.4	346.2	344.8	346.0	349.2	354.9	416.6	459.5	506.4
Other Conversions	10.9	13.3	12.3	14.3	15.3	17.4	17.3	15.4	12.4	14.5
Less Electricity, Steam, Coke and Coke Oven Gas	112.6	118.8	120.2	119.7	120.0	121.0	122.9	143.2	158.3	174.6
Primary Energy Demand	1375.9	1433.7	1427.8	1447.9	1459.9	1470.3	1479.2	1613.6	1757.1	1911.2
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	5.1	5.0	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Oil	335.2	358.5	361.5	362.9	364.3	364.4	362.9	377.5	401.1	433.9
Natural Gas	604.5	648.2	627.1	642.6	651.7	654.2	659.1	697.0	740.7	814.9
NGL-Gas Plant	37.8	32.7	32.3	32.2	31.9	31.6	31.5	32.9	35.2	37.1
Ethane	49.6	67.7	71.7	75.7	76.1	76.5	76.9	95.3	122.0	122.0
Coal	326.9	297.7	305.5	304.6	305.7	312.2	317.2	373.3	414.2	459.2
Renewables	16.8	23.9	23.8	24.0	24.2	25.5	25.7	31.6	37.9	38.3

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A3-2 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)	Alberta									
	High Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sectoral Demand										
Residential	190.5	197.2	194.7	198.3	195.6	193.9	192.9	191.3	198.3	209.7
Commercial	129.4	136.9	139.5	140.4	142.2	142.0	141.2	150.9	168.4	187.8
Industrial	163.7	180.6	184.3	185.8	190.1	195.5	201.8	265.8	305.9	356.4
Transportation - Road	197.5	197.8	197.3	195.7	194.6	193.5	192.8	193.6	204.9	218.3
- Air, Rail, Marine	47.0	50.9	51.8	53.2	53.8	54.1	53.6	55.3	57.6	60.7
- Total	244.5	248.7	249.1	248.9	248.4	247.6	246.4	249.0	262.5	279.0
Non-Energy [a]	313.1	350.4	361.6	376.3	381.1	384.3	389.1	419.9	462.8	480.3
Total End Use	1041.1	1113.8	1129.1	1149.8	1157.4	1163.2	1171.4	1276.8	1397.9	1513.2
Own Use	60.5	65.0	66.1	68.0	70.1	72.4	72.2	69.8	70.1	75.5
Electricity and Steam Generation [b][d]	376.0	360.4	354.9	362.3	370.4	381.0	394.6	490.2	550.1	607.0
Other Conversions	10.9	13.3	12.3	13.3	15.3	17.3	16.3	14.4	11.4	12.4
Less Electricity, Steam, Coke and Coke Oven Gas	112.6	118.8	123.0	125.3	127.8	131.2	135.5	165.8	186.2	205.9
Primary Energy Demand	1375.9	1433.7	1439.4	1468.2	1485.5	1502.8	1519.1	1685.4	1843.3	2002.3
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	5.1	5.0	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9
Oil	335.2	358.5	364.7	365.2	366.0	366.5	365.4	379.7	401.2	429.6
Natural Gas	604.5	648.2	632.1	650.9	661.5	661.5	669.0	712.7	739.7	809.2
NGL-Gas Plant	37.8	32.7	29.4	29.4	29.2	29.0	28.9	30.7	33.1	35.1
Ethane	49.6	67.7	71.7	75.7	76.1	76.5	76.9	95.3	122.0	122.0
Coal	326.9	297.7	311.9	317.1	322.6	338.0	347.4	429.5	503.5	562.4
Renewables	16.8	23.9	23.8	24.0	24.2	25.4	25.6	31.6	37.9	38.1

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A3-2 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules) — British Columbia and Territories — Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sectoral Demand										
Residential	126.4	130.3	131.0	133.1	133.4	136.5	137.1	141.9	150.1	158.1
Commercial	94.3	98.2	99.4	102.6	105.9	108.4	110.3	121.2	136.5	155.7
Industrial	388.1	413.3	434.3	446.1	453.3	459.1	460.9	480.8	519.4	574.5
Transportation - Road	158.3	155.7	155.4	154.7	154.2	153.7	153.4	155.3	166.5	181.5
- Air, Rail, Marine	48.9	48.7	52.3	56.0	59.1	60.5	60.5	67.5	75.5	82.7
- Total	207.2	204.4	207.7	210.7	213.3	214.2	214.0	222.8	241.9	264.3
Non-Energy [a]	35.7	41.0	42.3	47.6	49.6	50.1	50.6	56.7	65.7	68.8
Total End Use	851.7	887.2	914.7	940.1	955.4	968.3	972.8	1023.5	1113.6	1221.3
Own Use	47.7	53.7	55.8	58.2	61.1	64.1	65.9	55.5	60.4	68.2
Electricity and Steam Generation [b] [d]	173.0	188.2	202.0	205.4	210.8	216.0	219.2	234.9	263.8	297.1
Other Conversions	0.0	1.9	2.0	2.1	2.2	2.2	2.2	2.4	2.6	2.9
Less Electricity, Steam, Coke and Coke Oven Gas	168.7	176.8	188.4	190.6	194.4	198.1	200.7	212.2	237.6	267.7
Primary Energy Demand	903.8	954.1	986.2	1015.3	1035.1	1052.6	1059.5	1104.0	1202.8	1321.9
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	154.0	169.1	179.9	182.3	186.3	189.2	189.9	198.0	222.6	246.9
Oil	347.1	342.5	350.2	355.8	358.4	358.8	357.2	360.3	381.6	411.6
Natural Gas	195.4	207.7	212.8	226.1	237.3	247.6	254.2	267.9	312.2	366.3
NGL-Gas Plant	5.5	4.7	4.8	4.8	4.9	5.1	5.2	5.8	6.5	7.2
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	3.0	9.1	10.8	12.1	13.5	14.7	15.8	22.1	23.3	25.0
Renewables	198.7	221.0	227.8	234.1	234.8	237.2	237.1	249.9	256.6	265.0

Notes: [a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

Table A3-2 (Continued)
Total Energy Demand - End Use by Sector - Primary Demand by Fuel - Canada and Regions

(Petajoules)	British Columbia and Territories									
	High Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sectoral Demand										
Residential	126.4	130.3	130.7	131.6	130.6	132.2	131.7	131.4	137.3	143.0
Commercial	94.3	98.2	99.1	101.2	103.2	104.5	105.2	110.8	122.0	135.6
Industrial	388.1	413.3	431.4	438.1	440.8	442.7	441.1	450.7	473.0	506.2
Transportation - Road	158.3	155.7	155.0	153.9	152.8	151.7	150.7	146.5	149.8	156.3
- Air, Rail, Marine	48.9	48.7	51.1	53.4	54.9	55.7	55.4	59.3	65.1	70.4
- Total	207.2	204.4	206.1	207.3	207.7	207.4	206.0	205.8	214.9	226.7
Non-Energy [a]	35.7	41.0	42.3	47.4	49.3	49.8	50.3	56.2	64.8	67.4
Total End Use	851.7	887.2	909.7	925.6	931.5	936.7	934.4	954.8	1012.1	1078.9
Own Use	47.7	53.7	55.5	57.3	59.6	62.0	63.2	50.7	53.9	58.4
Electricity and Steam Generation [b] [d]	173.0	188.2	200.0	200.9	203.6	206.4	208.6	220.1	251.9	271.1
Other Conversions	0.0	1.9	2.0	2.1	2.1	2.2	2.1	2.2	2.4	2.6
Less Electricity, Steam, Coke and Coke Oven Gas	168.7	176.8	187.3	187.5	189.8	192.1	193.3	201.3	220.7	240.7
Primary Energy Demand	903.8	954.1	979.9	998.3	1007.0	1015.1	1015.1	1026.5	1099.7	1170.3
Primary Energy Demand by Fuel [c] [d]										
Nuclear [b]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro [b]	154.0	169.1	178.1	178.1	180.1	182.0	183.1	190.2	204.3	226.5
Oil	347.1	342.5	345.5	347.2	344.8	342.0	337.6	324.4	328.3	341.8
Natural Gas	195.4	207.7	212.7	221.9	228.9	234.1	236.4	235.7	283.0	308.5
NGL-Gas Plant	5.5	4.7	5.0	5.1	5.3	5.5	5.7	6.8	7.9	8.9
Ethane	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal	3.0	9.1	10.7	11.8	12.8	13.9	14.7	19.8	20.0	20.5
Renewables	198.7	221.0	227.9	234.3	235.1	237.5	237.5	249.7	256.0	264.1

Notes:[a] Includes Petrochemicals.
[b] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL - Gas Plant at primary fuels level.
[d] Fuels used to generate electricity exports are not included.

(Petajoules) 1984

History

	Natural Gas (1)	NGL (2)	Coal,Coke Coke Oven Gas (3)	Electricity (4)	Oil (5)	Steam (6)	Renewable (7)	Hydro[d] (8)	Nuclear [d] (9)	Total (10)
Sectoral Demand										
Residential	487	34	4	393	279	0	105	0	0	1302
Commercial	401	16	1	299	147	1	7	0	0	872
Petrochemical	290	77	0	0	116	0	0	0	0	484
Industrial [a]	565	12	234	577	319	46	351	0	0	2104
Transportation	0	12	0	3	1710	0	0	0	0	1725
Road	0	12	0	3	1383	0	0	0	0	1398
Rail	0	0	0	0	87	0	0	0	0	87
Air	0	0	0	0	155	0	0	0	0	155
Marine	0	0	0	0	85	0	0	0	0	85
Non-Energy Use [a]	0	0	0	0	191	0	0	0	0	191
Total End Use	1744	153	239	1271	2762	46	463	0	0	6678
Own Use and Conversions										
Own Use	127	8	1	119	223	0	0	0	0	479
Electricity Generation [d]	68	0	794	0	44	0	16	929	569	2420
Steam Production	0	0	5	0	6	0	0	0	36	48
Other Conversions	11	44	200	0	-44	0	0	0	0	211
Total Own Use and Conversions	206	52	1001	119	229	0	16	929	605	3158
Less Non-Primary Demand [b]	0	65	191	1390	-65	46	0	0	0	1627
Total Primary Demand [c]	1949	140	1049	0	3056	0	480	929	605	8209
Fuels for Electricity Exports [d]	0	0	119	0	19	0	0	92	27	256
Sub-Total	1949	140	1167	0	3075	0	480	1022	632	8465
Exports of Primary Energy	812	185	737	0	1014	0	0	0	0	2747
Total Disposition [e]	2761	325	1904	0	4088	0	480	1022	632	11212
Energy Imports	0	0	551	0	668	0	0	0	0	1219
Energy Production	2720	329	1396	0	3516	0	480	1022	632	10095
Total Primary Supply [e]	2720	329	1947	0	4184	0	480	1022	632	11314

Notes:[a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Disposition and supply may not balance due to inventory changes.

Table A3-3 (Continued)
Total Energy Balance - Canada

(Petajoules) — 1985 — History

	Natural Gas (1)	NGL (2)	Coal,Coke Coke Oven Gas (3)	Electricity (4)	Oil (5)	Steam (6)	Renewable (7)	Hydro [d] (8)	Nuclear [d] (9)	Total (10)
Sectoral Demand										
Residential	508	34	3	411	265	0	107	0	0	1329
Commercial	423	16	1	309	130	1	8	0	0	888
Petrochemical	305	100	0	0	132	0	0	0	0	537
Industrial [a]	610	12	264	611	274	40	378	0	0	2190
Transportation	1	14	0	3	1714	0	0	0	0	1732
Road	1	14	0	3	1389	0	0	0	0	1407
Rail	0	0	0	0	92	0	0	0	0	92
Air	0	0	0	0	160	0	0	0	0	160
Marine	0	0	0	0	73	0	0	0	0	73
Non-Energy Use [a]	0	0	0	0	211	0	0	0	0	211
Total End Use	1848	177	268	1334	2725	41	493	0	0	6886
Own Use and Conversions										
Own Use	133	17	4	125	221	0	0	0	0	500
Electricity Generation [d]	62	0	695	0	70	0	23	977	673	2500
Steam Production	0	0	3	0	7	0	0	0	41	51
Other Conversions	13	36	221	0	-36	0	0	0	0	234
Total Own Use and Conversions	208	53	923	125	262	0	23	977	715	3285
Less Non-Primary Demand [b]	0	74	211	1459	-74	41	0	0	0	1710
Total Primary Demand [c]	2056	156	980	0	3061	0	517	977	715	8461
Fuels for Electricity Exports [d]	0	0	106	0	3	0	0	111	21	241
Sub-Total	2056	156	1087	0	3064	0	517	1088	735	8701
Exports of Primary Energy	991	163	802	0	1419	0	0	0	0	3375
Total Disposition [e]	3047	319	1889	0	4483	0	517	1088	735	12077
Energy Imports	0	0	437	0	796	0	0	0	0	1233
Energy Production	3047	319	1487	0	3607	0	517	1088	735	10800
Total Primary Supply [e]	3047	319	1924	0	4403	0	517	1088	735	12032

Notes: [a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Disposition and supply may not balance due to inventory changes.

(Petajoules)

1986

Low Price Case

	Natural Gas	NGL	Coal,Coke Coke Oven Gas	Electricity	Oil [e]	Steam	Renewable	Hydro [d]	Nuclear [d]	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Sectoral Demand										
Residential	516	35	3	424	261	0	109	0	0	1347
Commercial	436	17	1	322	134	1	9	0	0	919
Petrochemical	318	108	0	0	128	0	0	0	0	554
Industrial [a]	623	13	285	643	307	34	386	0	0	2292
Transportation	2	15	0	3	1735	0	0	0	0	1755
Road	2	15	0	3	1393	0	0	0	0	1413
Rail	0	0	0	0	95	0	0	0	0	95
Air	0	0	0	0	165	0	0	0	0	165
Marine	0	0	0	0	82	0	0	0	0	82
Non-Energy Use [a]	0	0	0	0	217	0	0	0	0	217
Total End Use	1895	187	289	1393	2781	35	504	0	0	7084
Own Use and Conversions										
Own Use	133	18	5	133	226	0	0	0	0	514
Electricity Generation [d]	39	0	725	0	78	0	25	1013	763	2643
Steam Production	0	0	1	0	2	0	0	0	41	44
Other Conversions	12	36	241	0	-36	0	0	0	0	253
Total Own Use and Conversions	184	53	971	133	270	0	25	1013	805	3454
Less Non-Primary Demand [b]	0	76	229	1526	-76	35	0	0	0	1790
Total Primary Demand [c]	2078	164	1031	0	3127	0	529	1013	805	8747
Fuels for Electricity Exports [d]	0	0	62	0	0	0	0	120	22	204
Sub-Total	2078	164	1094	0	3127	0	529	1132	827	8952
Exports of Primary Energy	853	143	661	0	1688	0	0	0	0	3345
Total Disposition	2931	307	1755	0	4815	0	529	1132	827	12297
Energy Imports	0	0	373	0	976	0	0	0	0	1349
Energy Production	2931	307	1382	0	3874	0	529	1132	827	10983
Total Primary Supply	2931	307	1755	0	4850	0	529	1132	827	12331

Notes: [a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d]Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Differences in oil supply and disposition result from differences in conversion factors and treatment of gas plant butanes.

Table A3-3 (Continued)
Total Energy Balance - Canada

(Petajoules) — 1986 — High Price Case

	Natural Gas (1)	NGL (2)	Coal,Coke Coke Oven Gas (3)	Electricity (4)	Oil [e] (5)	Steam (6)	Renewable (7)	Hydro [d] (8)	Nuclear [d] (9)	Total (10)
Sectoral Demand										
Residential	515	35	3	424	255	0	109	0	0	1341
Commercial	436	17	1	322	132	1	9	0	0	917
Petrochemical	318	108	0	0	128	0	0	0	0	554
Industrial [a]	630	13	284	643	301	34	386	0	0	2291
Transportation	2	15	0	3	1726	0	0	0	0	1747
Road	2	15	0	3	1390	0	0	0	0	1410
Rail	0	0	0	0	94	0	0	0	0	94
Air	0	0	0	0	162	0	0	0	0	162
Marine	0	0	0	0	79	0	0	0	0	79
Non-Energy Use [a]	0	0	0	0	216	0	0	0	0	216
Total End Use	1900	187	288	1393	2758	35	504	0	0	7065
Own Use and Conversions										
Own Use	133	18	5	133	224	0	0	0	0	513
Electricity Generation [d]	41	0	714	0	78	0	25	1009	766	2634
Steam Production	0	0	1	0	2	0	0	0	41	44
Other Conversions	12	35	239	0	-35	0	0	0	0	251
Total Own Use and Conversions	186	53	958	133	269	0	25	1009	807	3442
Less Non-Primary Demand [b]	0	75	228	1526	-75	35	0	0	0	1789
Total Primary Demand [c]	2086	166	1018	0	3102	0	530	1009	807	8718
Fuels for Electricity Exports [d]	0	0	62	0	0	0	0	133	23	218
Sub-Total	2086	166	1080	0	3102	0	530	1142	830	8936
Exports of Primary Energy	853	142	661	0	1752	0	0	0	0	3408
Total Disposition	2939	308	1741	0	4854	0	530	1142	830	12344
Energy Imports	0	0	360	0	965	0	0	0	0	1325
Energy Production	2939	308	1381	0	3891	0	530	1142	830	11021
Total Primary Supply	2939	308	1741	0	4856	0	530	1142	830	12346

Notes:[a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d]Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Differences in oil supply and disposition result from differences in conversion factors and treatment of gas plant butanes.

(Petajoules) **1987**

Low Price Case

	Natural Gas (1)	NGL (2)	Coal,Coke Coke Oven Gas (3)	Electricity (4)	Oil [e] (5)	Steam (6)	Renewable (7)	Hydro [d] (8)	Nuclear [d] (9)	Total (10)
Sectoral Demand										
Residential	530	35	3	434	256	0	111	0	0	1369
Commercial	456	17	1	334	136	1	10	0	0	954
Petrochemical	333	121	0	0	114	0	0	0	0	568
Industrial [a]	660	13	300	658	320	35	395	0	0	2380
Transportation	2	15	0	3	1757	0	0	0	0	1777
Road	2	15	0	3	1398	0	0	0	0	1419
Rail	0	0	0	0	100	0	0	0	0	100
Air	0	0	0	0	171	0	0	0	0	171
Marine	0	0	0	0	87	0	0	0	0	87
Non-Energy Use [a]	0	0	0	0	222	0	0	0	0	222
Total End Use	1980	202	303	1429	2805	36	516	0	0	7271
Own Use and Conversions										
Own Use	145	20	5	136	228	0	0	0	0	534
Electricity Generation [d]	40	0	709	0	79	0	26	1032	876	2764
Steam Production	0	0	1	0	2	0	0	0	42	45
Other Conversions	14	35	253	0	-35	0	0	0	0	267
Total Own Use and Conversions	200	55	968	136	274	0	26	1032	918	3609
Less Non-Primary Demand [b]	0	79	241	1566	-79	36	0	0	0	1842
Total Primary Demand [c]	2179	179	1031	0	3158	0	542	1032	918	9038
Fuels for Electricity Exports [d]	0	0	62	0	0	0	0	136	25	224
Sub-Total	2179	179	1093	0	3158	0	542	1169	943	9262
Exports of Primary Energy	1014	140	664	0	1465	0	0	0	0	3284
Total Disposition	3193	319	1757	0	4623	0	542	1169	943	12546
Energy Imports	0	0	370	0	981	0	0	0	0	1351
Energy Production	3193	319	1388	0	3708	0	542	1169	943	11261
Total Primary Supply	3193	319	1757	0	4689	0	542	1169	943	12612

Notes: [a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Differences in oil supply and disposition result from differences in conversion factors and treatment of gas plant butanes.

Table A3-3 (Continued)
Total Energy Balance - Canada

(Petajoules) 1987

High Price Case

	Natural Gas (1)	NGL (2)	Coal,Coke Coke Oven Gas (3)	Electricity (4)	Oil [e] (5)	Steam (6)	Renewable (7)	Hydro [d] (8)	Nuclear [d] (9)	Total (10)
Sectoral Demand										
Residential	524	35	3	435	246	0	111	0	0	1353
Commercial	448	17	1	332	133	1	10	0	0	941
Petrochemical	333	121	0	0	114	0	0	0	0	568
Industrial [a]	647	13	293	650	311	34	395	0	0	2343
Transportation	3	16	0	4	1736	0	0	0	0	1760
Road	3	16	0	4	1389	0	0	0	0	1412
Rail	0	0	0	0	98	0	0	0	0	98
Air	0	0	0	0	167	0	0	0	0	167
Marine	0	0	0	0	83	0	0	0	0	83
Non-Energy Use [a]	0	0	0	0	221	0	0	0	0	221
Total End Use	1955	203	297	1421	2761	34	516	0	0	7186
Own Use and Conversions										
Own Use	143	20	5	136	225	0	0	0	0	528
Electricity Generation [d]	45	0	690	0	84	0	26	1022	878	2746
Steam Production	0	0	1	0	2	0	0	0	40	43
Other Conversions	13	35	247	0	-35	0	0	0	0	260
Total Own Use and Conversions	201	55	943	136	275	0	26	1022	918	3578
Less Non-Primary Demand [b]	0	77	236	1556	-77	34	0	0	0	1827
Total Primary Demand [c]	2156	181	1004	0	3114	0	542	1022	918	8937
Fuels for Electricity Exports [d]	0	0	62	0	0	0	0	149	26	237
Sub-Total	2156	181	1067	0	3114	0	542	1171	944	9175
Exports of Primary Energy	1014	137	664	0	1585	0	0	0	0	3401
Total Disposition	3170	318	1731	0	4699	0	542	1171	944	12575
Energy Imports	0	0	348	0	978	0	0	0	0	1326
Energy Production	3170	318	1383	0	3790	0	542	1171	944	11318
Total Primary Supply	3170	318	1731	0	4768	0	542	1171	944	12645

Notes:[a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Differences in oil supply and disposition result from differences in conversion factors and treatment of gas plant butanes.

(Petajoules)

1988

Low Price Case

	Natural Gas (1)	NGL (2)	Coal, Coke Coke Oven Gas (3)	Electricity (4)	Oil [e] (5)	Steam (6)	Renewable (7)	Hydro [d] (8)	Nuclear [d] (9)	Total (10)
Sectoral Demand										
Residential	544	35	3	448	252	0	113	0	0	1396
Commercial	474	18	1	343	137	1	11	0	0	985
Petrochemical	337	129	0	0	95	0	0	0	0	562
Industrial [a]	711	13	308	675	316	35	399	0	0	2458
Transportation	3	16	0	3	1777	0	0	0	0	1798
Road	3	16	0	3	1407	0	0	0	0	1429
Rail	0	0	0	0	102	0	0	0	0	102
Air	0	0	0	0	176	0	0	0	0	176
Marine	0	0	0	0	92	0	0	0	0	92
Non-Energy Use [a]	0	0	0	0	229	0	0	0	0	229
Total End Use	2069	212	312	1469	2806	36	523	0	0	7427
Own Use and Conversions										
Own Use	163	22	6	138	228	0	0	0	0	557
Electricity Generation [d]	42	0	653	0	89	0	27	1048	1025	2883
Steam Production	0	0	1	0	2	0	0	0	42	45
Other Conversions	15	35	259	0	-35	0	0	0	0	274
Total Own Use and Conversions	220	57	918	138	283	0	27	1048	1067	3759
Less Non-Primary Demand [b]	0	81	247	1607	-81	36	0	0	0	1890
Total Primary Demand [c]	2288	189	984	0	3170	0	550	1048	1067	9296
Fuels for Electricity Exports [d]	0	0	55	0	0	0	0	131	35	221
Sub-Total	2288	189	1038	0	3170	0	550	1179	1102	9516
Exports of Primary Energy	1233	150	668	0	1202	0	0	0	0	3253
Total Disposition	3521	339	1706	0	4372	0	550	1179	1102	12769
Energy Imports	0	0	333	0	993	0	0	0	0	1326
Energy Production	3521	339	1373	0	3443	0	550	1179	1102	11507
Total Primary Supply	3521	339	1706	0	4436	0	550	1179	1102	12833

Notes: [a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Differences in oil supply and disposition result from differences in conversion factors and treatment of gas plant butanes.

Table A3-3 (Continued)
Total Energy Balance - Canada

(Petajoules) — 1988 — High Price Case

	Natural Gas (1)	NGL (2)	Coal,Coke Coke Oven Gas (3)	Electricity (4)	Oil [e] (5)	Steam (6)	Renewable (7)	Hydro [d] (8)	Nuclear [d] (9)	Total (10)
Sectoral Demand										
Residential	529	35	3	448	237	0	113	0	0	1365
Commercial	457	18	1	340	132	1	11	0	0	960
Petrochemical	337	129	0	0	95	0	0	0	0	562
Industrial [a]	682	13	298	663	304	33	398	0	0	2392
Transportation	4	18	0	4	1744	0	0	0	0	1770
Road	4	18	0	4	1390	0	0	0	0	1416
Rail	0	0	0	0	99	0	0	0	0	99
Air	0	0	0	0	170	0	0	0	0	170
Marine	0	0	0	0	84	0	0	0	0	84
Non-Energy Use [a]	0	0	0	0	225	0	0	0	0	225
Total End Use	2009	213	302	1455	2737	34	522	0	0	7272
Own Use and Conversions										
Own Use	159	22	5	137	222	0	0	0	0	546
Electricity Generation [d]	49	0	626	0	91	0	27	1036	1024	2854
Steam Production	0	0	1	0	2	0	0	0	40	42
Other Conversions	15	35	252	0	-35	0	0	0	0	267
Total Own Use and Conversions	222	57	884	137	281	0	27	1036	1064	3708
Less Non-Primary Demand [b]	0	79	240	1592	-79	34	0	0	0	1866
Total Primary Demand [c]	2231	191	946	0	3097	0	549	1036	1064	9114
Fuels for Electricity Exports [d]	0	0	74	0	0	0	0	146	39	259
Sub-Total	2231	191	1020	0	3097	0	549	1182	1102	9373
Exports of Primary Energy	1233	129	668	0	1399	0	0	0	0	3429
Total Disposition	3464	320	1688	0	4496	0	549	1182	1102	12802
Energy Imports	0	0	310	0	961	0	0	0	0	1271
Energy Production	3464	320	1378	0	3597	0	549	1182	1102	11592
Total Primary Supply	3464	320	1688	0	4558	0	549	1182	1102	12863

Notes: [a] Excludes Petrochemicals.
[b]Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Differences in oil supply and disposition result from differences in conversion factors and treatment of gas plant butanes.

(Petajoules) 1989

Low Price Case

	Natural Gas	NGL	Coal,Coke Coke Oven Gas	Electricity	Oil [e]	Steam	Renewable	Hydro [d]	Nuclear [d]	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Sectoral Demand										
Residential	555	36	3	461	248	0	115	0	0	1417
Commercial	486	18	1	351	137	1	12	0	0	1007
Petrochemical	339	135	0	0	97	0	0	0	0	571
Industrial [a]	776	14	316	661	332	34	404	0	0	2536
Transportation	3	16	0	3	1794	0	0	0	0	1817
Road	3	16	0	3	1419	0	0	0	0	1442
Rail	0	0	0	0	104	0	0	0	0	104
Air	0	0	0	0	178	0	0	0	0	178
Marine	0	0	0	0	92	0	0	0	0	92
Non-Energy Use [a]	0	0	0	0	233	0	0	0	0	233
Total End Use	2159	220	320	1476	2841	35	531	0	0	7581
Own Use and Conversions										
Own Use	183	23	6	137	231	0	0	0	0	582
Electricity Generation [d]	40	0	671	0	97	0	29	1025	1094	2955
Steam Production	0	0	1	0	2	0	0	0	42	44
Other Conversions	17	35	265	0	-35	0	0	0	0	282
Total Own Use and Conversions	240	58	943	137	295	0	29	1025	1135	3863
Less Non-Primary Demand [b]	0	83	253	1613	-83	35	0	0	0	1901
Total Primary Demand [c]	2399	195	1010	0	3218	0	560	1025	1135	9542
Fuels for Electricity Exports [d]	0	0	56	0	0	0	0	138	41	236
Sub-Total	2399	195	1067	0	3218	0	560	1163	1176	9778
Exports of Primary Energy	1462	186	672	0	983	0	0	0	0	3303
Total Disposition	3861	381	1738	0	4201	0	560	1163	1176	13081
Energy Imports	0	0	341	0	1022	0	0	0	0	1363
Energy Production	3861	381	1397	0	3234	0	560	1163	1176	11773
Total Primary Supply	3861	381	1738	0	4256	0	560	1163	1176	13136

Notes: [a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Differences in oil supply and disposition result from differences in conversion factors and treatment of gas plant butanes.

Table A3-3 (Continued)
Total Energy Balance - Canada

(Petajoules) **1989**

High Price Case

	Natural Gas (1)	NGL (2)	Coal,Coke Coke Oven Gas (3)	Electricity (4)	Oil [e] (5)	Steam (6)	Renewable (7)	Hydro [d] (8)	Nuclear [d] (9)	Total (10)
Sectoral Demand										
Residential	531	35	3	461	228	0	114	0	0	1372
Commercial	462	18	1	347	130	1	12	0	0	971
Petrochemical	339	135	0	0	97	0	0	0	0	571
Industrial [a]	730	14	305	646	315	32	403	0	0	2444
Transportation	5	19	0	5	1749	0	0	0	0	1777
Road	5	19	0	5	1394	0	0	0	0	1423
Rail	0	0	0	0	101	0	0	0	0	101
Air	0	0	0	0	170	0	0	0	0	170
Marine	0	0	0	0	84	0	0	0	0	84
Non-Energy Use [a]	0	0	0	0	229	0	0	0	0	229
Total End Use	2067	220	308	1459	2748	33	529	0	0	7365
Own Use and Conversions										
Own Use	176	23	6	136	224	0	0	0	0	566
Electricity Generation [d]	44	0	629	0	102	0	29	1018	1090	2912
Steam Production	0	0	1	0	2	0	0	0	38	41
Other Conversions	17	35	257	0	-35	0	0	0	0	274
Total Own Use and Conversions	238	58	892	136	293	0	29	1018	1128	3792
Less Non-Primary Demand [b]	0	80	245	1596	-80	33	0	0	0	1873
Total Primary Demand [c]	2305	198	955	0	3121	0	558	1018	1128	9284
Fuels for Electricity Exports [d]	0	0	76	0	0	0	0	147	48	271
Sub-Total	2305	198	1031	0	3121	0	558	1165	1176	9555
Exports of Primary Energy	1462	130	672	0	1271	0	0	0	0	3535
Total Disposition	3767	328	1703	0	4392	0	558	1165	1176	13090
Energy Imports	0	0	302	0	969	0	0	0	0	1270
Energy Production	3767	328	1402	0	3479	0	558	1165	1176	11875
Total Primary Supply	3767	328	1703	0	4448	0	558	1165	1176	13145

Notes: [a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Differences in oil supply and disposition result from differences in conversion factors and treatment of gas plant butanes.

(Petajoules)

1990

Low Price Case

	Natural Gas (1)	NGL (2)	Coal,Coke Coke Oven Gas (3)	Electricity (4)	Oil [e] (5)	Steam (6)	Renewable (7)	Hydro [d] (8)	Nuclear [d] (9)	Total (10)
Sectoral Demand										
Residential	562	36	3	472	242	0	116	0	0	1431
Commercial	493	18	1	359	136	1	13	0	0	1021
Petrochemical	343	140	0	0	98	0	0	0	0	581
Industrial [a]	793	14	314	671	322	32	406	0	0	2553
Transportation	4	17	0	3	1807	0	0	0	0	1831
Road	4	17	0	3	1435	0	0	0	0	1459
Rail	0	0	0	0	105	0	0	0	0	105
Air	0	0	0	0	177	0	0	0	0	177
Marine	0	0	0	0	90	0	0	0	0	90
Non-Energy Use [a]	0	0	0	0	236	0	0	0	0	236
Total End Use	2195	226	317	1506	2841	33	536	0	0	7654
Own Use and Conversions										
Own Use	183	24	6	138	231	0	0	0	0	582
Electricity Generation [d]	44	0	694	0	72	0	30	1038	1160	3038
Steam Production	0	0	1	0	2	0	0	0	39	42
Other Conversions	17	35	262	0	-35	0	0	0	0	279
Total Own Use and Conversions	243	60	963	138	269	0	30	1038	1199	3940
Less Non-Primary Demand [b]	0	84	249	1644	-84	33	0	0	0	1926
Total Primary Demand [c]	2438	202	1031	0	3194	0	566	1038	1199	9668
Fuels for Electricity Exports [d]	0	0	69	0	0	0	0	149	50	267
Sub-Total	2438	202	1100	0	3194	0	566	1186	1249	9935
Exports of Primary Energy	1401	171	676	0	806	0	0	0	0	3054
Total Disposition	3839	373	1776	0	4000	0	566	1186	1249	12989
Energy Imports	0	0	327	0	1002	0	0	0	0	1330
Energy Production	3839	373	1449	0	3067	0	566	1186	1249	11729
Total Primary Supply	3839	373	1776	0	4069	0	566	1186	1249	13059

Notes:[a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Differences in oil supply and disposition result from differences in conversion factors and treatment of gas plant butanes.

Table A3-3 (Continued)
Total Energy Balance - Canada

(Petajoules) — 1990 — High Price Case

	Natural Gas (1)	NGL (2)	Coal,Coke Coke Oven Gas (3)	Electricity (4)	Oil [e] (5)	Steam (6)	Renewable (7)	Hydro [d] (8)	Nuclear [d] (9)	Total (10)
Sectoral Demand										
Residential	531	35	3	473	216	0	115	0	0	1373
Commercial	462	18	1	353	128	1	13	0	0	976
Petrochemical	343	140	0	0	98	0	0	0	0	581
Industrial [a]	737	14	301	657	301	30	406	0	0	2445
Transportation	6	20	0	5	1748	0	0	0	0	1779
Road	6	20	0	5	1399	0	0	0	0	1430
Rail	0	0	0	0	101	0	0	0	0	101
Air	0	0	0	0	168	0	0	0	0	168
Marine	0	0	0	0	80	0	0	0	0	80
Non-Energy Use [a]	0	0	0	0	233	0	0	0	0	233
Total End Use	2079	227	305	1489	2724	30	534	0	0	7388
Own Use and Conversions										
Own Use	174	24	6	137	221	0	0	0	0	563
Electricity Generation [d]	51	0	668	0	83	0	30	1022	1152	3006
Steam Production	0	0	1	0	2	0	0	0	35	38
Other Conversions	16	35	253	0	-35	0	0	0	0	269
Total Own Use and Conversions	241	59	928	137	272	0	30	1022	1187	3876
Less Non-Primary Demand [b]	0	81	241	1626	-81	30	0	0	0	1898
Total Primary Demand [c]	2319	205	992	0	3076	0	564	1022	1187	9366
Fuels for Electricity Exports [d]	0	0	90	0	0	0	0	166	61	317
Sub-Total	2319	205	1081	0	3076	0	564	1188	1248	9683
Exports of Primary Energy	1401	103	676	0	1231	0	0	0	0	3411
Total Disposition	3720	308	1757	0	4307	0	564	1188	1248	13095
Energy Imports	0	0	294	0	929	0	0	0	0	1223
Energy Production	3720	308	1463	0	3437	0	564	1188	1248	11929
Total Primary Supply	3720	308	1757	0	4366	0	564	1188	1248	13152

Notes:[a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Differences in oil supply and disposition result from differences in conversion factors and treatment of gas plant butanes.

(Petajoules) 1995

Low Price Case

	Natural Gas (1)	NGL (2)	Coal,Coke Coke Oven Gas (3)	Electricity (4)	Oil [e] (5)	Steam (6)	Renewable (7)	Hydro [d] (8)	Nuclear [d] (9)	Total (10)
Sectoral Demand										
Residential	585	37	3	523	213	0	124	0	0	1485
Commercial	545	21	1	412	124	1	19	0	0	1122
Petrochemical	360	162	0	0	100	0	0	0	0	622
Industrial [a]	915	16	350	764	310	27	420	0	0	2802
Transportation	6	18	0	4	1938	0	0	0	0	1966
Road	6	18	0	4	1531	0	0	0	0	1559
Rail	0	0	0	0	111	0	0	0	0	111
Air	0	0	0	0	195	0	0	0	0	195
Marine	0	0	0	0	101	0	0	0	0	101
Non-Energy Use [a]	0	0	0	0	259	0	0	0	0	259
Total End Use	2411	254	354	1703	2945	28	563	0	0	8256
Own Use and Conversions										
Own Use	168	26	9	153	239	0	0	0	0	596
Electricity Generation [d]	55	0	879	0	56	0	41	1150	1307	3488
Steam Production	0	0	1	0	2	0	0	0	32	34
Other Conversions	15	36	287	0	-36	0	0	0	0	302
Total Own Use and Conversions	238	62	1176	153	261	0	41	1150	1339	4420
Less Non-Primary Demand [b]	0	87	273	1856	-87	28	0	0	0	2157
Total Primary Demand [c]	2649	229	1257	0	3292	0	603	1150	1339	10519
Fuels for Electricity Exports [d]	0	0	107	0	0	0	0	137	53	297
Sub-Total	2649	229	1364	0	3292	0	603	1287	1392	10816
Exports of Primary Energy	526	153	754	0	772	0	0	0	0	2205
Total Disposition	3175	382	2117	0	4065	0	603	1287	1392	13021
Energy Imports	0	0	372	0	1717	0	0	0	0	2089
Energy Production	3175	382	1745	0	2450	0	603	1287	1392	11035
Total Primary Supply	3175	382	2117	0	4167	0	603	1287	1392	13124

Notes:[a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Differences in oil supply and disposition result from differences in conversion factors and treatment of gas plant butanes.

Table A3-3 (Continued)
Total Energy Balance - Canada

(Petajoules) **1995**

High Price Case

	Natural Gas (1)	NGL (2)	Coal,Coke Coke Oven Gas (3)	Electricity (4)	Oil [e] (5)	Steam (6)	Renewable (7)	Hydro [d] (8)	Nuclear [d] (9)	Total (10)
Sectoral Demand										
Residential	527	35	3	530	164	0	123	0	0	1382
Commercial	487	20	1	400	110	1	17	0	0	1036
Petrochemical	360	162	0	0	100	0	0	0	0	622
Industrial (a)	809	16	329	744	277	23	419	0	0	2617
Transportation	11	24	0	8	1789	0	0	0	0	1832
Road	11	24	0	8	1424	0	0	0	0	1466
Rail	0	0	0	0	105	0	0	0	0	105
Air	0	0	0	0	172	0	0	0	0	172
Marine	0	0	0	0	87	0	0	0	0	87
Non-Energy Use (a)	0	0	0	0	254	0	0	0	0	254
Total End Use	2195	256	333	1682	2693	24	560	0	0	7742
Own Use and Conversions										
Own Use	151	26	8	153	218	0	0	0	0	556
Electricity Generation (d)	65	0	911	0	45	0	41	1125	1297	3484
Steam Production	0	0	1	0	2	0	0	0	28	30
Other Conversions	14	34	271	0	-34	0	0	0	0	285
Total Own Use and Conversions	231	60	1191	153	231	0	41	1125	1325	4355
Less Non-Primary Demand (b)	0	81	258	1834	-81	24	0	0	0	2117
Total Primary Demand (c)	2425	235	1265	0	3005	0	600	1125	1325	9980
Fuels for Electricity Exports (d)	0	0	116	0	0	0	0	163	66	345
Sub-Total	2425	235	1381	0	3005	0	600	1289	1391	10325
Exports of Primary Energy	526	71	754	0	1424	0	0	0	0	2775
Total Disposition	2951	306	2134	0	4430	0	600	1289	1391	13100
Energy Imports	0	0	338	0	1268	0	0	0	0	1606
Energy Production	2951	306	1796	0	3261	0	600	1289	1391	11594
Total Primary Supply	2951	306	2134	0	4529	0	600	1289	1391	13199

Notes:[a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Differences in oil supply and disposition result from differences in conversion factors and treatment of gas plant butanes.

(Petajoules) 2000

Low Price Case

	Natural Gas [f] (1)	NGL (2)	Coal,Coke Coke Oven Gas (3)	Electricity (4)	Oil [e] (5)	Steam (6)	Renewable (7)	Hydro [d] (8)	Nuclear [d] (9)	Total (10)
Sectoral Demand										
Residential	616	39	3	573	198	0	132	0	0	1561
Commercial	610	24	1	476	112	1	29	0	0	1254
Petrochemical	386	188	0	0	100	0	0	0	0	675
Industrial [a]	1062	18	388	872	327	28	432	0	0	3127
Transportation	8	19	0	4	2091	0	0	0	0	2123
Road	8	19	0	4	1644	0	0	0	0	1676
Rail	0	0	0	0	120	0	0	0	0	120
Air	0	0	0	0	212	0	0	0	0	212
Marine	0	0	0	0	114	0	0	0	0	114
Non-Energy Use [a]	0	0	0	0	285	0	0	0	0	285
Total End Use	2683	289	392	1925	3114	29	593	0	0	9024
Own Use and Conversions										
Own Use	159	27	10	172	253	0	0	0	0	621
Electricity Generation [d]	60	0	1199	0	55	0	47	1278	1331	3970
Steam Production	0	0	1	0	2	0	0	0	34	36
Other Conversions	12	38	319	0	-38	0	0	0	0	331
Total Own Use and Conversions	232	65	1529	172	272	0	47	1278	1365	4959
Less Non-Primary Demand [b]	0	92	304	2097	-92	29	0	0	0	2430
Total Primary Demand [c]	2914	262	1616	0	3478	0	640	1278	1365	11553
Fuels for Electricity Exports [d]	0	0	152	0	0	0	0	142	27	321
Sub-Total	2914	262	1769	0	3478	0	640	1420	1392	11874
Exports of Primary Energy	0	39	841	0	689	0	0	0	0	1568
Total Disposition	2914	301	2609	0	4166	0	640	1420	1392	13443
Energy Imports	0	0	535	0	2213	0	0	0	0	2748
Energy Production	2704	301	2075	0	2062	0	640	1420	1392	10594
Total Primary Supply	2704	301	2609	0	4275	0	640	1420	1392	13341

Notes:[a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Differences in oil supply and disposition result from differences in conversion factors and treatment of gas plant butanes.
[f] Differences between natural gas supply and disposition reflect the cross-over of supply and demand in the later years of the projection.

Table A3-3 (Continued)
Total Energy Balance - Canada

(Petajoules) — 2000 — High Price Case

	Natural Gas (1)	NGL (2)	Coal,Coke Coke Oven Gas (3)	Electricity (4)	Oil [e] (5)	Steam (6)	Renewable (7)	Hydro [d] (8)	Nuclear [d] (9)	Total (10)
Sectoral Demand										
Residential	549	37	2	585	136	0	134	0	0	1444
Commercial	535	22	1	460	95	1	26	0	0	1141
Petrochemical	386	188	0	0	100	0	0	0	0	675
Industrial[a]	918	18	357	842	285	24	430	0	0	2873
Transportation	16	27	0	10	1858	0	0	0	0	1911
Road	16	27	0	10	1469	0	0	0	0	1523
Rail	0	0	0	0	112	0	0	0	0	112
Air	0	0	0	0	176	0	0	0	0	176
Marine	0	0	0	0	100	0	0	0	0	100
Non-Energy Use [a]	0	0	0	0	277	0	0	0	0	277
Total End Use	2404	292	360	1898	2751	25	590	0	0	8320
Own Use and Conversions										
Own Use	139	27	8	170	222	0	0	0	0	567
Electricity Generation [d]	69	0	1177	0	51	0	47	1252	1329	3925
Steam Production	0	0	1	0	2	0	0	0	28	31
Other Conversions	11	35	294	0	-35	0	0	0	0	305
Total Own Use and Conversions	218	62	1481	170	240	0	47	1252	1358	4828
Less Non-Primary Demand [b]	0	84	280	2068	-84	25	0	0	0	2373
Total Primary Demand [c]	2623	271	1561	0	3075	0	637	1252	1358	10776
Fuels for Electricity Exports [d]	0	0	174	0	0	0	0	135	32	341
Sub-Total	2623	271	1735	0	3075	0	637	1387	1390	11117
Exports of Primary Energy	0	12	841	0	1423	0	0	0	0	2275
Total Disposition	2623	283	2576	0	4497	0	637	1387	1390	13392
Energy Imports	0	0	459	0	1085	0	0	0	0	1544
Energy Production	2623	283	2116	0	3519	0	637	1387	1390	11955
Total Primary Supply	2623	283	2576	0	4604	0	637	1387	1390	13500

Notes:[a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Differences in oil supply and disposition result from differences in conversion factors and treatment of gas plant butanes.

(Petajoules)

2005

Low Price Case

	Natural Gas [f]	NGL	Coal,Coke Coke Oven Gas	Electricity	Oil [e]	Steam	Renewable	Hydro [d]	Nuclear [d]	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Sectoral Demand										
Residential	648	41	2	619	194	0	142	0	0	1648
Commercial	693	27	2	552	110	1	35	0	0	1420
Petrochemical	400	188	0	0	100	0	0	0	0	688
Industrial [a]	1283	21	446	1037	367	31	444	0	0	3629
Transportation	11	20	0	5	2243	0	0	0	0	2279
Road	11	20	0	5	1754	0	0	0	0	1790
Rail	0	0	0	0	128	0	0	0	0	128
Air	0	0	0	0	231	0	0	0	0	231
Marine	0	0	0	0	130	0	0	0	0	130
Non-Energy Use [a]	0	0	0	0	318	0	0	0	0	318
Total End Use	3034	298	450	2213	3334	32	621	0	0	9983
Own Use and Conversions										
Own Use	182	28	10	194	276	0	0	0	0	691
Electricity Generation [d]	71	0	1488	0	116	0	49	1422	1495	4641
Steam Production	0	0	1	0	2	0	0	0	37	40
Other Conversions	14	39	369	0	-39	0	0	0	0	383
Total Own Use and Conversions	267	67	1868	194	355	0	49	1422	1532	5755
Less Non-Primary Demand [b]	0	99	351	2408	-99	32	0	0	0	2791
Total Primary Demand [c]	3302	267	1966	0	3787	0	670	1422	1532	12946
Fuels for Electricity Exports [d]	0	0	157	0	0	0	0	128	23	307
Sub-Total	3302	267	2123	0	3787	0	670	1550	1555	13253
Exports of Primary Energy	0	0	939	0	637	0	0	0	0	1576
Total Disposition	3302	267	3061	0	4424	0	670	1550	1555	14829
Energy Imports	0	105	658	0	2769	0	0	0	0	3531
Energy Production	1751	162	2404	0	1726	0	670	1550	1555	9818
Total Primary Supply	1751	267	3061	0	4495	0	670	1550	1555	13349

Notes:[a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Differences in oil supply and disposition result from differences in conversion factors and treatment of gas plant butanes.
[f] Differences between natural gas supply and disposition reflect the cross-over of supply and demand in the later years of the projection.

Table A3-3 (Continued)
Total Energy Balance - Canada

(Petajoules) **2005**

High Price Case

	Natural Gas [f] (1)	NGL (2)	Coal,Coke Coke Oven Gas (3)	Electricity (4)	Oil [e] (5)	Steam (6)	Renewable (7)	Hydro [d] (8)	Nuclear [d] (9)	Total (10)
Sectoral Demand										
Residential	576	39	2	636	124	0	146	0	0	1523
Commercial	596	25	1	525	90	1	31	0	0	1269
Petrochemical	400	188	0	0	100	0	0	0	0	688
Industrial [a]	1091	20	400	986	313	26	441	0	0	3277
Transportation	20	30	0	13	1931	0	0	0	0	1994
Road	20	30	0	13	1514	0	0	0	0	1578
Rail	0	0	0	0	118	0	0	0	0	118
Air	0	0	0	0	185	0	0	0	0	185
Marine	0	0	0	0	113	0	0	0	0	113
Non-Energy Use [a]	0	0	0	0	305	0	0	0	0	305
Total End Use	2682	303	404	2160	2863	27	618	0	0	9057
Own Use and Conversions										
Own Use	155	29	9	190	231	0	0	0	0	615
Electricity Generation [d]	68	0	1405	0	65	0	49	1388	1572	4547
Steam Production	0	0	1	0	2	0	0	0	31	34
Other Conversions	12	36	330	0	-36	0	0	0	0	342
Total Own Use and Conversions	236	64	1745	190	263	0	49	1388	1603	5538
Less Non-Primary Demand [b]	0	88	315	2350	-88	27	0	0	0	2692
Total Primary Demand [c]	2918	279	1834	0	3214	0	667	1388	1603	11903
Fuels for Electricity Exports [d]	0	0	180	0	0	0	0	124	28	333
Sub-Total	2918	279	2014	0	3214	0	667	1512	1632	12235
Exports of Primary Energy	0	8	939	0	1680	0	0	0	0	2627
Total Disposition	2918	287	2953	0	4894	0	667	1512	1632	14862
Energy Imports	0	0	540	0	1495	0	0	0	0	2035
Energy Production	2604	287	2413	0	3495	0	667	1512	1632	12609
Total Primary Supply	2604	287	2953	0	4990	0	667	1512	1632	14644

Notes:[a] Excludes Petrochemicals.
[b] Oil products include refinery LPG for the purpose of calculating primary energy demand.
[c] Butanes for blending in gasoline is excluded from oil and included in NGL at primary fuels level.
[d] Hydro and Nuclear are converted at 3.6 GJ/MWh and 12.1 GJ/MWh respectively.
[e] Differences in oil supply and disposition result from differences in conversion factors and treatment of gas plant butanes.
[f] Differences between natural gas supply and disposition reflect the cross-over of supply and demand in the later years of the projection.

Table A3-4
Historical Data - End Use Energy Demand by Fuel - Canada

(Petajoules)	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Electricity	470.9	512.6	542.6	579.4	624.2	664.0	698.7	758.2	816.5	872.0
Oil Products	2202.9	2316.8	2466.7	2612.3	2739.8	2923.0	2968.3	3165.7	3295.3	3384.2
Natural Gas	545.5	600.5	652.6	719.0	816.1	879.2	974.7	1092.9	1112.3	1222.7
NGL	37.0	46.7	47.3	46.4	55.4	53.5	63.2	67.7	66.4	82.1
Coal,Coke and Coke Oven Gas	429.8	410.2	377.2	366.9	320.7	313.0	257.4	250.0	262.5	253.3
Renewables and Steam	88.8	82.6	81.5	78.1	72.5	68.7	62.6	56.6	57.3	58.4
Total	3775.0	3969.3	4167.9	4402.1	4628.8	4901.4	5024.8	5391.2	5610.2	5872.8

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Electricity	856.9	918.3	986.7	1032.7	1059.3	1100.7	1139.2	1128.9	1180.9	1270.9
Oil Products	3289.7	3391.4	3416.7	3475.8	3618.5	3555.4	3336.5	2964.6	2774.7	2761.6
Natural Gas	1208.0	1326.5	1416.6	1495.8	1554.2	1557.1	1535.6	1584.5	1606.7	1743.5
NGL	77.3	88.8	89.6	64.6	94.9	105.1	111.9	102.0	122.5	153.0
Coal,Coke and Coke Oven Gas	234.3	242.2	236.6	246.6	255.2	252.8	227.1	205.4	215.5	238.8
Renewables and Steam	62.6	319.7	319.2	394.6	455.8	488.2	472.7	505.6	522.1	509.9
Total	5728.8	6286.8	6465.4	6710.1	7038.1	7059.4	6823.0	6491.1	6422.5	6677.7

Table A3-5
Relative Energy Prices by Region and Sector

(Percent)

Atlantic

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Natural Gas / Electricity	1.00	0.92	0.87	0.77	0.76	0.78	0.80	0.83	0.82	0.82
Light Fuel Oil / Electricity	1.00	1.00	0.69	0.69	0.68	0.70	0.72	0.75	0.74	0.74
Natural Gas / Light Fuel Oil	1.00	0.92	1.26	1.12	1.12	1.11	1.11	1.10	1.11	1.11
Commercial										
Natural Gas / Electricity	0.93	0.95	0.92	0.84	0.83	0.84	0.86	0.88	0.87	0.87
Light Fuel Oil / Electricity	0.54	0.59	0.38	0.37	0.37	0.38	0.39	0.41	0.41	0.41
Natural Gas / Light Fuel Oil	1.73	1.62	2.43	2.25	2.27	2.22	2.17	2.12	2.13	2.13
Natural Gas / Heavy Fuel Oil	2.07	1.93	3.49	3.24	3.34	3.26	3.16	3.01	3.04	3.04
Industrial										
Natural Gas / Electricity	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heavy Fuel Oil / Electricity	0.49	0.55	0.29	0.29	0.27	0.29	0.30	0.32	0.32	0.32
Natural Gas / Heavy Fuel Oil	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Natural Gas / Electricity	1.00	0.92	0.88	0.83	0.84	0.87	0.91	0.98	0.97	0.97
Light Fuel Oil / Electricity	1.00	1.00	0.74	0.75	0.76	0.79	0.83	0.91	0.90	0.90
Natural Gas / Light Fuel Oil	1.00	0.92	1.20	1.10	1.10	1.10	1.09	1.08	1.08	1.08
Commercial										
Natural Gas / Electricity	0.93	0.95	0.92	0.88	0.89	0.91	0.94	0.99	0.98	0.98
Light Fuel Oil / Electricity	0.54	0.59	0.41	0.41	0.42	0.45	0.47	0.52	0.52	0.52
Natural Gas / Light Fuel Oil	1.73	1.62	2.28	2.13	2.11	2.04	1.98	1.89	1.90	1.90
Natural Gas / Heavy Fuel Oil	2.07	1.93	3.14	2.89	2.89	2.79	2.66	2.43	2.46	2.46
Industrial										
Natural Gas / Electricity	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heavy Fuel Oil / Electricity	0.49	0.55	0.33	0.34	0.34	0.36	0.39	0.45	0.44	0.44
Natural Gas / Heavy Fuel Oil	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Note: Relative electricity prices should not be compared to previous published projections. See note on Table A3-8.

(Percent) **Quebec**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Natural Gas / Electricity	0.93	0.91	0.92	0.77	0.76	0.79	0.82	0.86	0.86	0.86
Light Fuel Oil / Electricity	1.34	1.38	0.99	0.99	0.98	1.02	1.05	1.10	1.09	1.09
Natural Gas / Light Fuel Oil	0.69	0.66	0.93	0.78	0.78	0.78	0.78	0.79	0.79	0.79
Commercial										
Natural Gas / Electricity	0.66	0.62	0.62	0.50	0.50	0.52	0.54	0.58	0.57	0.57
Light Fuel Oil / Electricity	0.89	0.89	0.58	0.58	0.57	0.60	0.63	0.66	0.66	0.66
Natural Gas / Light Fuel Oil	0.75	0.70	1.07	0.87	0.86	0.87	0.87	0.87	0.87	0.87
Natural Gas / Heavy Fuel Oil	0.94	0.88	1.84	1.49	1.50	1.46	1.43	1.38	1.39	1.39
Industrial										
Natural Gas / Electricity	0.67	0.67	0.60	0.45	0.45	0.48	0.51	0.55	0.54	0.54
Heavy Fuel Oil / Electricity	0.74	0.83	0.40	0.40	0.39	0.42	0.45	0.49	0.49	0.49
Natural Gas / Heavy Fuel Oil	0.91	0.80	1.51	1.14	1.14	1.13	1.12	1.11	1.11	1.11

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Natural Gas / Electricity	0.93	0.91	0.93	0.85	0.87	0.93	0.98	1.09	1.08	1.08
Light Fuel Oil / Electricity	1.34	1.38	1.06	1.09	1.11	1.17	1.23	1.35	1.34	1.34
Natural Gas / Light Fuel Oil	0.69	0.66	0.88	0.79	0.79	0.79	0.80	0.81	0.81	0.81
Commercial										
Natural Gas / Electricity	0.66	0.62	0.63	0.57	0.58	0.62	0.66	0.75	0.74	0.74
Light Fuel Oil / Electricity	0.89	0.89	0.63	0.65	0.67	0.71	0.76	0.85	0.84	0.84
Natural Gas / Light Fuel Oil	0.75	0.70	1.00	0.87	0.87	0.87	0.88	0.88	0.88	0.88
Natural Gas / Heavy Fuel Oil	0.94	0.88	1.63	1.40	1.38	1.34	1.31	1.25	1.26	1.26
Industrial										
Natural Gas / Electricity	0.67	0.67	0.61	0.54	0.55	0.61	0.66	0.77	0.76	0.76
Heavy Fuel Oil / Electricity	0.74	0.83	0.46	0.48	0.50	0.55	0.60	0.71	0.70	0.70
Natural Gas / Heavy Fuel Oil	0.91	0.80	1.35	1.12	1.11	1.10	1.09	1.08	1.08	1.08

Note: Relative electricity prices should not be compared to previous published projections. See note on Table A3-8.

Table A3-5 (Continued)
Relative Energy Prices by Region and Sector

(Percent) — Ontario

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Natural Gas / Electricity	0.76	0.72	0.67	0.54	0.53	0.56	0.58	0.62	0.61	0.61
Light Fuel Oil / Electricity	1.22	1.21	0.79	0.79	0.78	0.81	0.84	0.88	0.87	0.87
Natural Gas / Light Fuel Oil	0.62	0.59	0.85	0.68	0.68	0.69	0.69	0.70	0.70	0.70
Commercial										
Natural Gas / Electricity	0.53	0.49	0.45	0.35	0.34	0.36	0.38	0.41	0.41	0.41
Light Fuel Oil / Electricity	0.83	0.82	0.49	0.49	0.48	0.51	0.53	0.56	0.56	0.56
Natural Gas / Light Fuel Oil	0.64	0.60	0.93	0.71	0.71	0.72	0.72	0.73	0.73	0.73
Natural Gas / Heavy Fuel Oil	0.80	0.73	1.40	1.07	1.07	1.06	1.05	1.03	1.03	1.03
Industrial										
Natural Gas / Electricity	0.68	0.60	0.55	0.39	0.39	0.42	0.44	0.49	0.48	0.48
Heavy Fuel Oil / Electricity	0.85	0.82	0.40	0.39	0.39	0.42	0.45	0.49	0.48	0.48
Natural Gas / Heavy Fuel Oil	0.80	0.73	1.38	1.00	1.00	1.00	1.00	1.00	1.00	1.00

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Natural Gas / Electricity	0.76	0.72	0.68	0.61	0.63	0.67	0.71	0.81	0.80	0.80
Light Fuel Oil / Electricity	1.22	1.21	0.85	0.87	0.89	0.94	0.99	1.09	1.08	1.08
Natural Gas / Light Fuel Oil	0.62	0.59	0.80	0.70	0.71	0.71	0.72	0.74	0.74	0.74
Commercial										
Natural Gas / Electricity	0.53	0.49	0.46	0.40	0.42	0.45	0.49	0.57	0.56	0.56
Light Fuel Oil / Electricity	0.83	0.82	0.53	0.55	0.57	0.61	0.65	0.73	0.72	0.72
Natural Gas / Light Fuel Oil	0.64	0.60	0.86	0.73	0.74	0.75	0.76	0.78	0.77	0.77
Natural Gas / Heavy Fuel Oil	0.80	0.73	1.25	1.04	1.03	1.02	1.00	0.98	0.98	0.98
Industrial										
Natural Gas / Electricity	0.68	0.60	0.56	0.47	0.49	0.55	0.60	0.71	0.69	0.70
Heavy Fuel Oil / Electricity	0.85	0.82	0.45	0.47	0.49	0.55	0.60	0.70	0.69	0.69
Natural Gas / Heavy Fuel Oil	0.80	0.73	1.23	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Note: Relative electricity prices should not be compared to previous published projections. See note on Table A3-8.

(Percent)

Manitoba

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Natural Gas / Electricity	0.86	0.82	0.76	0.56	0.54	0.57	0.60	0.63	0.62	0.62
Light Fuel Oil / Electricity	1.70	1.70	1.14	1.11	1.08	1.11	1.14	1.17	1.16	1.16
Natural Gas / Light Fuel Oil	0.50	0.48	0.67	0.50	0.50	0.51	0.52	0.54	0.54	0.54
Commercial										
Natural Gas / Electricity	0.49	0.49	0.45	0.31	0.30	0.32	0.34	0.37	0.36	0.36
Light Fuel Oil / Electricity	0.91	0.97	0.60	0.58	0.57	0.59	0.61	0.63	0.63	0.63
Natural Gas / Light Fuel Oil	0.54	0.50	0.75	0.53	0.53	0.55	0.56	0.58	0.58	0.58
Natural Gas / Heavy Fuel Oil	0.66	0.62	1.19	0.85	0.85	0.85	0.85	0.84	0.84	0.84
Industrial										
Natural Gas / Electricity	0.59	0.58	0.53	0.33	0.32	0.35	0.38	0.42	0.41	0.41
Heavy Fuel Oil / Electricity	0.92	0.97	0.47	0.45	0.44	0.47	0.50	0.54	0.53	0.53
Natural Gas / Heavy Fuel Oil	0.64	0.60	1.13	0.73	0.73	0.74	0.76	0.77	0.77	0.77

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Natural Gas / Electricity	0.86	0.82	0.77	0.66	0.67	0.73	0.80	0.92	0.90	0.90
Light Fuel Oil / Electricity	1.70	1.70	1.22	1.23	1.24	1.31	1.38	1.51	1.50	1.50
Natural Gas / Light Fuel Oil	0.50	0.48	0.64	0.54	0.54	0.56	0.58	0.61	0.60	0.60
Commercial										
Natural Gas / Electricity	0.49	0.49	0.46	0.38	0.39	0.43	0.47	0.56	0.55	0.55
Light Fuel Oil / Electricity	0.91	0.97	0.65	0.66	0.67	0.72	0.76	0.85	0.84	0.84
Natural Gas / Light Fuel Oil	0.54	0.50	0.70	0.58	0.58	0.60	0.62	0.65	0.65	0.65
Natural Gas / Heavy Fuel Oil	0.66	0.62	1.06	0.85	0.85	0.84	0.84	0.84	0.84	0.84
Industrial										
Natural Gas / Electricity	0.59	0.58	0.54	0.43	0.45	0.51	0.57	0.69	0.67	0.67
Heavy Fuel Oil / Electricity	0.92	0.97	0.54	0.56	0.57	0.63	0.70	0.82	0.81	0.81
Natural Gas / Heavy Fuel Oil	0.64	0.60	1.00	0.77	0.78	0.80	0.81	0.84	0.83	0.83

Note: Relative electricity prices should not be compared to previous published projections. See note on Table A3-8.

Table A3-5 (Continued)
Relative Energy Prices by Region and Sector

(Percent)

Saskatchewan

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Natural Gas / Electricity	0.49	0.44	0.39	0.25	0.24	0.26	0.28	0.31	0.30	0.30
Light Fuel Oil / Electricity	1.18	1.11	0.70	0.67	0.64	0.66	0.68	0.71	0.71	0.71
Natural Gas / Light Fuel Oil	0.41	0.40	0.55	0.38	0.37	0.39	0.41	0.43	0.43	0.43
Commercial										
Natural Gas / Electricity	0.24	0.21	0.18	0.11	0.10	0.11	0.13	0.14	0.14	0.14
Light Fuel Oil / Electricity	0.61	0.57	0.35	0.33	0.31	0.33	0.34	0.36	0.35	0.35
Natural Gas / Light Fuel Oil	0.40	0.38	0.53	0.33	0.33	0.35	0.37	0.40	0.39	0.39
Natural Gas / Heavy Fuel Oil	0.49	0.40	0.77	0.48	0.48	0.49	0.50	0.52	0.52	0.52
Industrial										
Natural Gas / Electricity	0.29	0.26	0.22	0.12	0.11	0.13	0.14	0.17	0.16	0.16
Heavy Fuel Oil / Electricity	0.64	0.61	0.27	0.26	0.25	0.27	0.29	0.31	0.31	0.31
Natural Gas / Heavy Fuel Oil	0.46	0.43	0.80	0.47	0.46	0.49	0.51	0.53	0.53	0.53

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Natural Gas / Electricity	0.49	0.44	0.40	0.31	0.32	0.35	0.39	0.47	0.46	0.46
Light Fuel Oil / Electricity	1.18	1.11	0.75	0.74	0.73	0.78	0.82	0.90	0.90	0.90
Natural Gas / Light Fuel Oil	0.41	0.40	0.52	0.42	0.43	0.46	0.48	0.52	0.51	0.51
Commercial										
Natural Gas / Electricity	0.24	0.21	0.19	0.14	0.15	0.17	0.19	0.23	0.22	0.23
Light Fuel Oil / Electricity	0.61	0.57	0.37	0.37	0.36	0.39	0.41	0.46	0.45	0.45
Natural Gas / Light Fuel Oil	0.40	0.38	0.50	0.39	0.40	0.43	0.46	0.50	0.50	0.50
Natural Gas / Heavy Fuel Oil	0.49	0.40	0.68	0.52	0.52	0.54	0.55	0.57	0.57	0.57
Industrial										
Natural Gas / Electricity	0.64	0.61	0.32	0.32	0.32	0.36	0.39	0.47	0.46	0.46
Heavy Fuel Oil / Electricity	0.46	0.43	0.71	0.52	0.54	0.56	0.58	0.61	0.61	0.61
Natural Gas / Heavy Fuel Oil	0.43	0.43	0.41	0.43	0.45	0.49	0.54	0.63	0.62	0.62

Note: Relative electricity prices should not be compared to previous published projections. See note on Table A3-8.

Table A3-5 (Continued)
Relative Energy Prices by Region and Sector

(Percent) **Alberta**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Natural Gas / Electricity	0.43	0.43	0.41	0.37	0.36	0.39	0.41	0.44	0.44	0.44
Light Fuel Oil / Electricity	1.08	1.10	0.68	0.68	0.68	0.71	0.73	0.77	0.76	0.77
Natural Gas / Light Fuel Oil	0.40	0.39	0.59	0.54	0.53	0.55	0.56	0.57	0.57	0.57
Commercial										
Natural Gas / Electricity	0.26	0.25	0.23	0.20	0.20	0.22	0.24	0.26	0.26	0.26
Light Fuel Oil / Electricity	0.78	0.77	0.46	0.46	0.46	0.48	0.50	0.53	0.52	0.52
Natural Gas / Light Fuel Oil	0.34	0.33	0.51	0.44	0.44	0.46	0.48	0.50	0.50	0.50
Natural Gas / Heavy Fuel Oil	0.45	0.36	0.71	0.62	0.62	0.63	0.63	0.64	0.64	0.64
Industrial										
Natural Gas / Electricity	0.25	0.25	0.23	0.19	0.19	0.21	0.23	0.27	0.26	0.26
Heavy Fuel Oil / Electricity	0.76	0.77	0.36	0.36	0.35	0.38	0.41	0.45	0.44	0.44
Natural Gas / Heavy Fuel Oil	0.33	0.33	0.65	0.54	0.53	0.56	0.58	0.60	0.60	0.60

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Natural Gas / Electricity	0.43	0.43	0.41	0.43	0.45	0.49	0.54	0.63	0.62	0.62
Light Fuel Oil / Electricity	1.08	1.10	0.74	0.76	0.78	0.83	0.88	0.98	0.97	0.97
Natural Gas / Light Fuel Oil	0.40	0.39	0.56	0.57	0.58	0.60	0.61	0.64	0.64	0.64
Commercial										
Natural Gas / Electricity	0.26	0.25	0.24	0.26	0.27	0.30	0.33	0.40	0.39	0.40
Light Fuel Oil / Electricity	0.78	0.77	0.50	0.52	0.53	0.57	0.60	0.68	0.67	0.67
Natural Gas / Light Fuel Oil	0.34	0.33	0.48	0.49	0.50	0.53	0.55	0.59	0.59	0.59
Natural Gas / Heavy Fuel Oil	0.45	0.36	0.63	0.64	0.64	0.65	0.66	0.67	0.67	0.67
Industrial										
Natural Gas / Electricity	0.25	0.25	0.24	0.26	0.27	0.31	0.36	0.44	0.43	0.44
Heavy Fuel Oil / Electricity	0.76	0.77	0.41	0.43	0.45	0.50	0.55	0.65	0.64	0.64
Natural Gas / Heavy Fuel Oil	0.33	0.33	0.57	0.59	0.60	0.63	0.65	0.68	0.68	0.68

Note: Relative electricity prices should not be compared to previous published projections. See note on Table A3-8.

Table A3-5 (Continued)
Relative Energy Prices by Region and Sector

(Percent) — British Columbia and Territories

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Natural Gas / Electricity	0.58	0.57	0.52	0.46	0.46	0.48	0.50	0.54	0.53	0.53
Light Fuel Oil / Electricity	1.17	1.19	0.79	0.79	0.79	0.82	0.85	0.89	0.88	0.88
Natural Gas / Light Fuel Oil	0.50	0.48	0.66	0.58	0.58	0.59	0.60	0.61	0.60	0.60
Commercial										
Natural Gas / Electricity	0.41	0.40	0.36	0.32	0.31	0.33	0.35	0.37	0.37	0.37
Light Fuel Oil / Electricity	0.74	0.72	0.44	0.44	0.43	0.45	0.47	0.50	0.50	0.50
Natural Gas / Light Fuel Oil	0.56	0.55	0.82	0.73	0.72	0.73	0.73	0.74	0.74	0.74
Natural Gas / Heavy Fuel Oil	0.77	0.74	1.36	1.20	1.21	1.18	1.16	1.13	1.14	1.14
Industrial										
Natural Gas / Electricity	0.48	0.45	0.39	0.33	0.32	0.35	0.37	0.41	0.40	0.40
Heavy Fuel Oil / Electricity	0.67	0.67	0.33	0.33	0.32	0.35	0.37	0.41	0.40	0.40
Natural Gas / Heavy Fuel Oil	0.71	0.67	1.19	1.00	1.00	1.00	1.00	1.00	1.00	1.00

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Natural Gas / Electricity	0.58	0.57	0.54	0.53	0.54	0.58	0.63	0.71	0.70	0.70
Light Fuel Oil / Electricity	1.17	1.19	0.85	0.88	0.90	0.95	1.00	1.11	1.10	1.10
Natural Gas / Light Fuel Oil	0.50	0.48	0.63	0.60	0.61	0.62	0.63	0.64	0.64	0.64
Commercial										
Natural Gas / Electricity	0.41	0.40	0.37	0.36	0.37	0.40	0.44	0.50	0.49	0.49
Light Fuel Oil / Electricity	0.74	0.72	0.48	0.49	0.51	0.55	0.58	0.66	0.65	0.65
Natural Gas / Light Fuel Oil	0.56	0.55	0.77	0.74	0.74	0.74	0.75	0.75	0.75	0.75
Natural Gas / Heavy Fuel Oil	0.77	0.74	1.22	1.15	1.13	1.11	1.09	1.05	1.05	1.05
Industrial										
Natural Gas / Electricity	0.48	0.45	0.40	0.40	0.41	0.45	0.50	0.59	0.58	0.58
Heavy Fuel Oil / Electricity	0.67	0.67	0.37	0.39	0.41	0.45	0.50	0.59	0.58	0.58
Natural Gas / Heavy Fuel Oil	0.71	0.67	1.07	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Note: Relative electricity prices should not be compared to previous published projections. See note on Table A3-8.

(Petajoules)

Canada

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	1270.9	1333.6	1392.6	1429.4	1469.3	1475.9	1505.6	1702.7	1924.6	2213.4
Oil Products	2761.6	2725.2	2780.9	2805.2	2806.2	2840.5	2841.2	2944.5	3113.9	3333.7
Natural Gas	1743.5	1848.3	1894.5	1979.6	2068.6	2158.7	2194.7	2410.8	2682.8	3034.4
NGL	153.0	176.9	186.7	202.1	212.2	219.7	225.9	253.7	288.7	298.0
Coal,Coke and Coke Oven Gas	238.8	267.7	289.4	303.5	312.0	320.1	317.4	354.0	392.0	449.8
Renewables and Steam	509.9	534.1	539.3	551.5	558.6	566.1	569.3	590.2	622.3	653.2
Total	6677.7	6885.8	7083.5	7271.3	7426.9	7581.0	7654.0	8256.1	9024.2	9982.5

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	1270.9	1333.6	1392.5	1420.7	1455.4	1459.4	1488.8	1682.0	1897.5	2159.7
Oil Products	2761.6	2725.2	2758.1	2761.5	2737.3	2747.9	2724.0	2693.3	2750.6	2862.9
Natural Gas	1743.5	1848.3	1900.3	1954.7	2009.0	2067.1	2078.8	2194.7	2404.4	2682.2
NGL	153.0	176.9	187.3	202.8	212.9	220.5	226.9	255.7	292.3	303.0
Coal,Coke and Coke Oven Gas	238.8	267.7	287.6	296.7	302.0	308.2	304.9	332.6	360.2	403.8
Renewables and Steam	509.9	534.1	539.3	550.0	555.6	562.0	564.4	583.6	615.1	645.5
Total	6677.7	6885.8	7065.1	7186.4	7272.2	7365.1	7387.7	7742.0	8320.2	9057.1

Table A3-6 (Continued)
End Use Demand by Fuel - Canada and Regions

(Petajoules) **Atlantic**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	90.9	92.8	98.4	100.8	102.3	104.9	108.0	122.4	142.6	170.8
Oil Products	315.5	312.0	323.0	329.7	333.7	335.8	335.8	338.8	354.8	383.8
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2
NGL	4.6	4.6	4.8	4.9	4.9	5.0	5.1	5.3	5.8	6.3
Coal,Coke and Coke Oven Gas	7.9	9.1	9.5	9.7	9.7	9.8	9.7	10.2	11.1	12.7
Renewables and Steam	73.0	71.4	66.4	67.4	68.2	69.3	70.2	72.5	75.4	78.9
Total	491.9	489.9	502.1	512.6	519.0	524.8	528.9	549.2	589.9	652.7

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	90.9	92.8	98.6	101.0	103.2	106.3	110.2	124.8	148.5	175.5
Oil Products	315.5	312.0	321.5	326.1	328.4	328.9	327.5	319.9	329.9	350.0
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2
NGL	4.6	4.6	4.8	4.9	5.0	5.0	5.1	5.4	6.0	6.5
Coal,Coke and Coke Oven Gas	7.9	9.1	9.5	9.6	9.6	9.6	9.6	9.9	10.6	11.9
Renewables and Steam	73.0	71.4	66.3	67.2	67.9	68.9	69.7	73.2	78.3	83.7
Total	491.9	489.9	500.6	508.8	514.1	518.7	522.2	533.2	573.4	627.7

(Petajoules)

Newfoundland

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	30.9	30.9	32.4	33.0	33.2	33.7	35.8	37.3	40.7	49.6
Oil Products	77.0	76.5	77.7	79.6	80.7	81.0	81.8	76.6	84.8	91.1
Total	122.9	121.3	123.7	126.3	127.8	128.6	131.9	127.6	140.0	155.9

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	30.9	30.9	32.8	33.7	35.4	36.9	40.3	41.9	53.1	63.9
Oil Products	77.0	76.5	77.6	79.1	80.3	80.5	81.0	78.7	80.0	83.4
Total	122.9	121.3	123.9	126.6	129.7	131.8	136.3	136.0	149.9	165.2

(Petajoules)

Prince Edward Island

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.3	2.6	2.8
Oil Products	13.9	13.8	14.2	14.4	14.7	14.8	14.7	15.7	16.7	18.3
Total	18.0	18.0	18.4	18.7	19.0	19.2	19.3	20.6	22.0	24.2

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	1.8	1.9	1.9	2.0	2.0	2.1	2.1	2.4	2.6	2.8
Oil Products	13.9	13.8	14.1	14.3	14.3	14.4	14.2	14.4	15.2	16.3
Total	18.0	18.0	18.3	18.5	18.7	18.8	18.7	19.4	20.8	22.6

Table A3-6 (Continued)
End Use Demand by Fuel - Canada and Regions

(Petajoules)

Nova Scotia

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	24.3	25.6	27.0	27.3	27.3	28.0	28.2	33.3	39.7	47.1
Oil Products	128.1	125.5	132.9	134.6	135.3	136.1	135.4	140.5	145.1	157.1
Total	184.8	184.0	187.9	190.2	190.9	192.7	192.3	204.2	217.1	239.1

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	24.3	25.6	26.9	27.1	26.9	27.4	27.4	32.5	37.6	43.9
Oil Products	128.1	125.5	132.3	133.3	133.1	133.2	131.9	130.5	134.9	143.8
Total	184.8	184.0	187.3	188.5	188.2	189.0	187.8	193.3	205.4	223.9

(Petajoules)

New Brunswick

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	33.9	34.4	37.1	38.6	39.7	41.2	42.0	49.5	59.6	71.3
Oil Products	96.5	96.1	98.2	101.1	103.1	103.9	103.9	106.1	108.2	117.2
Total	166.2	166.6	172.1	177.4	181.3	184.2	185.4	196.9	210.7	233.3

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	33.9	34.4	37.0	38.2	38.9	39.9	40.4	48.1	55.1	64.9
Oil Products	96.5	96.1	97.4	99.5	100.6	100.8	100.4	96.3	99.9	106.4
Total	166.2	166.6	171.1	175.2	177.4	179.2	179.4	184.6	197.3	216.0

(Petajoules)

Quebec

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	445.4	477.5	497.9	510.9	524.6	507.7	521.1	590.9	666.5	762.3
Oil Products	655.3	613.1	625.5	630.3	631.2	650.4	644.3	656.9	683.9	724.6
Natural Gas	159.6	185.4	188.5	198.4	213.0	250.2	257.1	290.6	324.2	368.9
NGL	16.7	17.5	19.4	20.1	20.7	23.5	26.0	28.0	29.1	30.6
Coal,Coke and Coke Oven Gas	17.4	22.0	22.8	23.1	23.3	23.7	23.4	23.2	23.3	23.9
Renewables and Steam	86.8	89.9	91.7	93.6	96.0	98.1	99.9	105.1	111.1	115.5
Total	1381.2	1405.4	1445.8	1476.5	1508.8	1553.7	1571.8	1694.8	1838.1	2026.0

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	445.4	477.5	496.8	506.0	517.0	498.5	511.0	577.1	648.4	734.4
Oil Products	655.3	613.1	619.5	619.6	613.9	625.4	611.3	586.7	586.3	603.8
Natural Gas	159.6	185.4	190.3	195.3	204.8	235.7	238.1	252.8	274.7	308.0
NGL	16.7	17.5	19.4	20.1	20.6	23.3	25.7	27.6	28.7	30.0
Coal,Coke and Coke Oven Gas	17.4	22.0	22.7	22.6	22.4	22.5	22.0	21.1	20.7	20.9
Renewables and Steam	86.8	89.9	91.9	93.7	96.0	98.1	99.8	104.6	110.4	114.5
Total	1381.2	1405.4	1440.6	1457.3	1474.7	1503.6	1507.9	1569.9	1669.1	1811.7

Table A3-6 (Continued)
End Use Demand by Fuel - Canada and Regions

(Petajoules) **Ontario**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	396.6	409.9	428.7	445.4	464.4	478.3	485.0	553.7	626.3	729.1
Oil Products	919.2	916.6	942.2	948.9	942.5	955.0	964.4	1026.5	1088.7	1157.0
Natural Gas	710.6	737.5	767.4	808.7	860.2	895.0	908.7	1012.8	1128.4	1293.8
NGL	43.9	47.6	51.1	61.2	69.9	73.8	77.0	80.8	83.3	86.4
Coal,Coke and Coke Oven Gas	200.7	221.5	240.5	252.7	260.0	266.4	263.1	288.1	321.0	371.0
Renewables and Steam	123.5	121.1	123.4	126.0	128.9	130.4	130.4	131.7	144.7	156.5
Total	2394.5	2454.2	2553.3	2642.8	2725.8	2798.9	2828.5	3093.6	3392.3	3793.9

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	396.6	409.9	427.9	439.3	454.1	465.2	470.5	530.9	598.6	693.7
Oil Products	919.2	916.6	933.2	932.0	914.8	916.9	915.2	916.7	929.0	952.5
Natural Gas	710.6	737.5	768.0	789.2	819.9	836.5	835.8	882.9	967.2	1094.9
NGL	43.9	47.6	51.4	61.4	70.1	74.0	77.2	81.2	84.4	88.3
Coal,Coke and Coke Oven Gas	200.7	221.5	238.9	247.0	251.5	256.7	253.2	269.9	293.3	330.3
Renewables and Steam	123.5	121.1	123.2	124.5	126.0	126.6	126.0	125.7	136.7	147.0
Total	2394.5	2454.2	2542.6	2593.4	2636.5	2675.9	2677.9	2807.5	3009.3	3306.8

(Petajoules)

Manitoba

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	44.8	46.8	49.2	51.6	52.9	54.2	55.2	63.1	72.1	83.1
Oil Products	100.2	101.9	102.2	103.2	103.9	104.7	105.3	113.7	126.0	138.1
Natural Gas	67.4	71.3	73.0	77.5	80.5	83.0	84.6	93.8	104.0	114.9
NGL	2.9	2.9	2.9	3.0	3.0	2.9	2.9	3.2	3.6	3.9
Coal,Coke and Coke Oven Gas	2.8	2.9	3.0	3.3	3.4	3.5	3.5	4.2	4.7	5.5
Renewables and Steam	9.7	11.3	11.9	12.6	13.2	13.9	14.6	16.1	18.5	20.3
Total	227.8	237.0	242.2	251.1	256.8	262.2	266.1	294.1	328.9	365.8

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	44.8	46.8	49.2	51.2	52.4	53.6	54.6	62.9	71.2	80.9
Oil Products	100.2	101.9	101.2	101.6	101.5	101.6	101.4	104.5	112.1	119.2
Natural Gas	67.4	71.3	73.2	76.2	77.7	78.9	79.5	84.1	91.1	98.2
NGL	2.9	2.9	2.9	3.0	3.0	3.0	3.0	3.3	3.7	4.1
Coal,Coke and Coke Oven Gas	2.8	2.9	3.0	3.2	3.3	3.3	3.3	3.8	4.2	4.8
Renewables and Steam	9.7	11.3	11.9	12.5	13.1	13.8	14.4	15.8	17.9	19.4
Total	227.8	237.0	241.3	247.7	251.0	254.2	256.1	274.3	300.1	326.5

Table A3-6 (Continued)
End Use Demand by Fuel - Canada and Regions

(Petajoules) — **Saskatchewan**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	37.1	37.4	39.2	39.9	40.3	41.6	43.1	47.3	55.6	64.3
Oil Products	132.5	134.2	133.2	131.7	130.5	130.1	129.7	131.8	142.9	157.3
Natural Gas	99.9	105.4	107.4	113.5	119.0	125.7	131.4	142.1	164.2	186.5
NGL	4.2	4.7	4.9	5.0	5.1	5.2	5.4	5.5	5.9	6.2
Coal,Coke and Coke Oven Gas	4.4	4.8	4.9	5.1	5.2	5.5	5.7	5.4	5.5	5.3
Renewables and Steam	11.2	11.8	12.0	12.2	12.3	12.5	12.7	13.2	13.9	14.4
Total	289.4	298.3	301.6	307.4	312.4	320.6	327.9	345.3	387.9	434.0

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	37.1	37.4	39.4	40.1	41.0	42.8	44.6	50.3	59.0	67.0
Oil Products	132.5	134.2	132.0	129.8	128.0	127.0	125.9	123.7	129.1	137.1
Natural Gas	99.9	105.4	108.0	111.7	115.4	120.0	123.8	127.6	145.2	162.5
NGL	4.2	4.7	4.9	5.0	5.1	5.2	5.4	5.5	5.9	6.2
Coal,Coke and Coke Oven Gas	4.4	4.8	4.9	5.1	5.2	5.4	5.6	5.2	5.2	4.9
Renewables and Steam	11.2	11.8	12.0	12.1	12.3	12.4	12.6	13.1	13.8	14.4
Total	289.4	298.3	301.2	303.8	307.0	312.8	317.8	325.4	358.3	392.2

(Petajoules)

Alberta

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	102.0	107.8	107.8	107.4	107.8	108.7	110.4	130.5	144.6	160.2
Oil Products	320.4	335.4	336.4	337.8	339.0	339.0	337.7	350.4	371.9	401.4
Natural Gas	530.6	564.2	568.8	580.5	586.1	588.6	593.1	629.6	679.1	742.7
NGL	72.1	90.4	94.4	98.5	99.0	99.3	99.7	120.3	149.3	151.8
Coal,Coke and Coke Oven Gas	2.0	1.8	1.9	1.9	2.0	2.0	2.0	8.9	11.7	15.6
Renewables and Steam	13.9	14.2	14.4	14.6	14.8	15.0	15.2	15.8	16.8	17.2
Total	1041.1	1113.8	1123.7	1140.7	1148.7	1152.6	1158.0	1255.5	1373.5	1488.9

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	102.0	107.8	110.4	112.5	115.0	118.1	121.9	151.2	170.4	189.2
Oil Products	320.4	335.4	336.5	336.9	337.6	337.8	336.8	348.9	368.3	393.3
Natural Gas	530.6	564.2	571.4	584.9	588.7	590.5	595.1	629.0	677.6	741.4
NGL	72.1	90.4	94.6	99.0	99.5	100.0	100.5	121.7	151.3	154.3
Coal,Coke and Coke Oven Gas	2.0	1.8	1.8	1.9	1.9	1.9	2.0	10.2	13.6	18.0
Renewables and Steam	13.9	14.2	14.4	14.6	14.8	14.9	15.1	15.8	16.8	17.0
Total	1041.1	1113.8	1129.1	1149.8	1157.4	1163.2	1171.4	1276.8	1397.9	1513.2

Table A3-6 (Continued)
End Use Demand by Fuel - Canada and Regions

(Petajoules)

British Columbia and Territories

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	154.1	161.4	171.4	173.4	176.9	180.4	182.9	194.9	217.0	243.5
Oil Products	318.5	312.1	318.4	323.6	325.5	325.5	324.0	326.4	345.6	371.6
Natural Gas	175.3	184.5	189.5	201.0	209.7	216.3	219.7	242.0	282.8	327.4
NGL	8.6	9.1	9.3	9.5	9.6	9.8	9.9	10.6	11.6	12.7
Coal,Coke and Coke Oven Gas	3.5	5.7	6.8	7.6	8.5	9.3	10.0	14.0	14.7	15.8
Renewables and Steam	191.7	214.4	219.4	225.1	225.2	227.0	226.4	235.7	241.9	250.3
Total	851.7	887.2	914.7	940.1	955.4	968.3	972.8	1023.5	1113.6	1221.3

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Electricity	154.1	161.4	170.3	170.5	172.7	175.0	176.0	184.8	201.5	218.9
Oil Products	318.5	312.1	314.3	315.5	313.2	310.2	305.9	292.9	295.8	306.9
Natural Gas	175.3	184.5	189.5	197.3	202.4	205.5	206.4	218.1	248.5	277.1
NGL	8.6	9.1	9.3	9.5	9.7	9.9	10.0	11.0	12.4	13.6
Coal,Coke and Coke Oven Gas	3.5	5.7	6.7	7.4	8.1	8.8	9.3	12.6	12.6	13.0
Renewables and Steam	191.7	214.4	219.5	225.3	225.5	227.3	226.8	235.5	241.3	249.4
Total	851.7	887.2	909.7	925.6	931.5	936.7	934.4	954.8	1012.1	1078.9

Table A3-7
Distribution of End Use Demand by Fuel and Sector Canada and Regions

(Percent) Canada

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Electricity	30.2	30.9	31.5	31.7	32.1	32.5	33.0	35.2	36.7	37.6
Oil	21.4	19.9	19.3	18.7	18.1	17.5	16.9	14.4	12.7	11.8
Natural Gas	37.4	38.3	38.3	38.7	39.0	39.2	39.3	39.4	39.5	39.3
Wood	7.9	7.9	7.9	7.9	7.9	7.9	7.9	8.0	8.0	8.1
Other	3.1	3.0	3.0	3.0	2.9	2.9	2.9	3.0	3.1	3.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Commercial										
Electricity	34.2	34.8	35.1	35.0	34.8	34.9	35.1	36.7	38.0	38.9
Oil	16.9	14.7	14.6	14.2	13.9	13.6	13.3	11.0	9.0	7.8
Natural Gas	46.0	47.7	47.4	47.7	48.1	48.3	48.3	48.5	48.7	48.8
Other	2.9	2.9	3.0	3.1	3.1	3.2	3.3	3.7	4.4	4.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Industrial										
Electricity	27.4	27.9	28.1	27.7	27.5	26.0	26.3	27.2	27.9	28.6
Oil	15.2	12.5	13.4	13.4	12.9	13.1	12.6	11.1	10.5	10.1
Natural Gas	26.8	27.9	27.2	27.7	28.9	30.6	31.1	32.7	34.0	35.4
Coal, Coke and Coke Oven Gas	11.1	12.0	12.5	12.6	12.5	12.5	12.3	12.5	12.4	12.3
Steam	2.2	1.8	1.5	1.5	1.4	1.4	1.3	0.9	0.9	0.9
Wood Waste	16.7	17.3	16.8	16.5	16.0	15.7	15.6	14.6	13.3	11.6
Other	0.6	0.6	0.6	0.7	0.7	0.8	0.8	1.0	1.1	1.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total End Use										
Electricity	19.0	19.4	19.7	19.7	19.8	19.5	19.7	20.6	21.3	22.2
Oil	41.4	39.6	39.3	38.6	37.8	37.5	37.1	35.7	34.5	33.4
Natural Gas	26.1	26.8	26.7	27.2	27.9	28.5	28.7	29.2	29.7	30.4
Coal, Coke and Coke Oven Gas	3.6	3.9	4.1	4.2	4.2	4.2	4.1	4.3	4.3	4.5
Steam	0.7	0.6	0.5	0.5	0.5	0.5	0.4	0.3	0.3	0.3
Wood	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.4	1.4	1.3
Wood Waste	5.3	5.5	5.4	5.4	5.3	5.2	5.2	5.0	4.6	4.2
Other	2.4	2.7	2.8	3.0	3.1	3.2	3.3	3.5	3.8	3.7
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table A3-7 (Continued)
Distribution of End Use Demand by Fuel and Sector Canada and Regions

(Percent)	Canada									
	High Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Electricity	30.2	30.9	31.6	32.1	32.8	33.6	34.5	38.3	40.5	41.7
Oil	21.4	19.9	19.0	18.2	17.4	16.6	15.8	11.8	9.4	8.2
Natural Gas	37.4	38.3	38.4	38.7	38.8	38.7	38.7	38.2	38.0	37.8
Wood	7.9	7.9	8.0	8.0	8.0	8.1	8.2	8.6	8.8	9.0
Other	3.1	3.0	3.0	3.0	2.9	2.9	2.9	3.1	3.2	3.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Commercial										
Electricity	34.2	34.8	35.1	35.3	35.4	35.7	36.2	38.6	40.3	41.4
Oil	16.9	14.7	14.4	14.1	13.8	13.4	13.1	10.6	8.4	7.1
Natural Gas	46.0	47.7	47.5	47.5	47.7	47.6	47.3	47.0	46.9	46.9
Other	2.9	2.9	3.0	3.1	3.2	3.2	3.3	3.7	4.5	4.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Industrial										
Electricity	27.4	27.9	28.1	27.7	27.7	26.4	26.9	28.4	29.3	30.1
Oil	15.2	12.5	13.2	13.3	12.7	12.9	12.3	10.6	9.9	9.5
Natural Gas	26.8	27.9	27.5	27.6	28.5	29.9	30.1	30.9	31.9	33.3
Coal, Coke and Coke Oven Gas	11.1	12.0	12.4	12.5	12.5	12.5	12.3	12.6	12.4	12.2
Steam	2.2	1.8	1.5	1.4	1.4	1.3	1.2	0.9	0.8	0.8
Wood Waste	16.7	17.3	16.8	16.7	16.5	16.3	16.3	15.6	14.5	12.9
Other	0.6	0.6	0.6	0.7	0.7	0.8	0.9	1.0	1.1	1.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total End Use										
Electricity	19.0	19.4	19.7	19.8	20.0	19.8	20.2	21.7	22.8	23.8
Oil	41.4	39.6	39.0	38.4	37.6	37.3	36.9	34.8	33.1	31.6
Natural Gas	26.1	26.8	26.9	27.2	27.6	28.1	28.1	28.3	28.9	29.6
Coal, Coke and Coke Oven Gas	3.6	3.9	4.1	4.1	4.2	4.2	4.1	4.3	4.3	4.5
Steam	0.7	0.6	0.5	0.5	0.5	0.4	0.4	0.3	0.3	0.3
Wood	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Wood Waste	5.3	5.5	5.4	5.5	5.4	5.4	5.4	5.3	5.0	4.7
Other	2.4	2.7	2.8	3.0	3.2	3.3	3.4	3.7	4.1	4.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table A3-7 (Continued)
Distribution of End Use Demand by Fuel and Sector Canada and Regions

(Percent)	Atlantic									
	Low Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Electricity	26.7	27.2	27.3	27.4	27.4	27.6	27.8	30.7	34.6	37.1
Oil	45.8	46.2	46.2	46.3	46.4	46.3	46.1	42.9	38.3	35.3
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	24.4	23.8	23.7	23.7	23.7	23.7	23.7	24.0	24.4	24.7
Other	3.1	2.9	2.7	2.6	2.5	2.4	2.4	2.4	2.6	2.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Commercial										
Electricity	30.9	33.9	36.1	37.7	39.1	40.7	42.3	48.9	54.3	59.4
Oil	64.7	61.8	59.4	57.7	56.2	54.5	52.9	46.1	40.5	35.2
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2
Other	4.4	4.3	4.4	4.5	4.7	4.7	4.7	5.0	5.1	5.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Industrial										
Electricity	28.5	28.8	29.9	29.2	28.8	28.8	29.1	30.9	32.2	34.3
Oil	36.9	35.9	39.0	39.8	40.2	40.3	40.0	37.6	37.5	38.2
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal, Coke and Coke Oven Gas	3.9	5.0	5.2	5.2	5.3	5.3	5.2	5.4	5.5	5.6
Steam	6.2	4.7	0.8	0.8	0.7	0.7	0.7	0.6	0.6	0.5
Wood Waste	24.0	25.1	24.4	24.1	24.1	24.0	23.9	24.2	22.8	20.0
Other	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.4	1.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total End Use										
Electricity	18.5	18.9	19.6	19.7	19.7	20.0	20.4	22.3	24.2	26.2
Oil	64.1	63.7	64.3	64.3	64.3	64.0	63.5	61.7	60.1	58.8
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal, Coke and Coke Oven Gas	1.6	1.9	1.9	1.9	1.9	1.9	1.8	1.9	1.9	1.9
Steam	2.0	1.5	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2
Wood	5.2	5.2	5.1	5.1	5.1	5.1	5.1	5.2	5.1	5.0
Wood Waste	7.5	7.7	7.6	7.6	7.6	7.6	7.6	7.4	7.0	6.3
Other	1.0	1.1	1.1	1.2	1.2	1.2	1.3	1.4	1.5	1.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table A3-7 (Continued)
Distribution of End Use Demand by Fuel and Sector Canada and Regions

(Percent)	Atlantic									
	High Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Electricity	26.7	27.2	27.4	27.6	27.8	28.1	28.5	31.7	35.5	37.5
Oil	45.8	46.2	46.1	46.0	46.0	45.7	45.3	40.4	34.5	30.6
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	24.4	23.8	23.8	23.7	23.7	23.8	23.8	25.5	27.3	29.0
Other	3.1	2.9	2.7	2.6	2.5	2.4	2.4	2.4	2.6	2.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Commercial										
Electricity	30.9	33.9	36.2	37.9	39.4	41.2	42.9	50.3	56.7	61.9
Oil	64.7	61.8	59.3	57.5	55.9	54.0	52.3	44.6	38.0	32.7
Natural Gas	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2
Other	4.4	4.3	4.4	4.5	4.7	4.7	4.8	5.0	5.2	5.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Industrial										
Electricity	28.5	28.8	30.0	29.4	29.3	29.4	30.1	32.3	34.4	36.3
Oil	36.9	35.9	39.0	39.7	40.1	40.0	39.6	36.8	36.4	37.2
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal, Coke and Coke Oven Gas	3.9	5.0	5.1	5.2	5.1	5.1	5.0	5.2	5.1	5.1
Steam	6.2	4.7	0.8	0.8	0.7	0.7	0.7	0.6	0.6	0.5
Wood Waste	24.0	25.1	24.4	24.2	23.9	23.7	23.5	23.9	22.1	19.5
Other	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.4	1.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total End Use										
Electricity	18.5	18.9	19.7	19.8	20.1	20.5	21.1	23.4	25.9	28.0
Oil	64.1	63.7	64.2	64.1	63.9	63.4	62.7	60.0	57.5	55.8
Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal, Coke and Coke Oven Gas	1.6	1.9	1.9	1.9	1.9	1.8	1.8	1.8	1.9	1.9
Steam	2.0	1.5	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2
Wood	5.2	5.2	5.1	5.1	5.0	5.1	5.1	5.4	5.7	6.0
Wood Waste	7.5	7.7	7.7	7.6	7.6	7.6	7.7	7.6	7.2	6.5
Other	1.0	1.1	1.1	1.2	1.2	1.3	1.3	1.4	1.6	1.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

(Percent) **Quebec**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Electricity	47.5	49.8	50.3	51.0	52.2	53.2	54.3	58.4	60.7	62.1
Oil	30.8	27.2	26.3	25.3	23.7	22.3	20.9	15.1	11.7	9.9
Natural Gas	8.5	9.9	10.1	10.4	10.8	11.1	11.3	12.6	13.3	13.5
Wood	11.4	11.7	11.7	11.8	11.8	11.9	11.9	12.1	12.4	12.6
Other	1.7	1.4	1.5	1.5	1.5	1.5	1.6	1.8	1.9	1.9
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Commercial										
Electricity	46.0	49.1	49.6	49.5	49.5	49.6	50.2	53.0	56.7	58.4
Oil	28.8	22.5	22.2	21.6	21.1	20.6	20.2	18.1	14.3	13.2
Natural Gas	20.4	23.2	23.0	23.6	24.2	24.6	24.4	23.6	23.6	23.0
Other	4.9	5.2	5.2	5.2	5.2	5.2	5.3	5.3	5.4	5.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Industrial										
Electricity	47.4	49.2	49.4	49.1	48.6	41.9	42.5	44.7	46.0	47.5
Oil	18.1	13.0	13.8	13.7	13.0	15.3	14.1	11.1	10.3	10.1
Natural Gas	20.4	23.1	22.4	22.9	24.2	28.9	29.6	31.0	31.4	31.6
Coal, Coke and Coke Oven Gas	3.6	4.4	4.3	4.3	4.2	4.1	4.0	3.7	3.3	2.9
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	10.0	9.9	9.5	9.4	9.3	8.9	9.0	8.3	7.6	6.6
Other	0.6	0.5	0.6	0.7	0.8	0.8	0.9	1.1	1.4	1.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total End Use										
Electricity	32.2	34.0	34.4	34.6	34.8	32.7	33.2	34.9	36.3	37.6
Oil	47.4	43.6	43.3	42.7	41.8	41.9	41.0	38.8	37.2	35.8
Natural Gas	11.6	13.2	13.0	13.4	14.1	16.1	16.4	17.1	17.6	18.2
Coal, Coke and Coke Oven Gas	1.3	1.6	1.6	1.6	1.5	1.5	1.5	1.4	1.3	1.2
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.3	2.3	2.2
Wood Waste	3.5	3.5	3.5	3.4	3.4	3.3	3.3	3.1	2.9	2.7
Other	1.6	1.7	1.8	1.9	1.9	2.1	2.3	2.4	2.4	2.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table A3-7 (Continued)
Distribution of End Use Demand by Fuel and Sector Canada and Regions

(Percent)	Quebec									
	High Price Case									
	1984	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Residential										
Electricity	47.5	49.8	50.5	51.5	53.0	54.5	56.0	62.4	66.4	68.8
Oil	30.8	27.2	25.9	24.6	22.8	21.0	19.3	11.7	7.2	4.6
Natural Gas	8.5	9.9	10.3	10.5	10.6	10.7	10.8	11.2	11.3	11.1
Wood	11.4	11.7	11.8	11.9	12.1	12.2	12.3	12.8	13.2	13.5
Other	1.7	1.4	1.5	1.5	1.5	1.5	1.6	1.8	1.9	2.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Commercial										
Electricity	46.0	49.1	49.7	49.9	50.1	50.4	51.3	55.5	60.1	62.1
Oil	28.8	22.5	22.0	21.4	20.8	20.3	19.8	17.4	13.4	12.2
Natural Gas	20.4	23.2	23.1	23.5	23.8	24.0	23.6	21.7	21.1	20.2
Other	4.9	5.2	5.2	5.2	5.3	5.3	5.3	5.4	5.5	5.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Industrial										
Electricity	47.4	49.2	49.4	49.2	48.9	42.5	43.4	46.6	48.0	49.2
Oil	18.1	13.0	13.4	13.4	12.6	14.7	13.1	9.5	8.6	8.4
Natural Gas	20.4	23.1	22.7	22.9	23.9	28.5	29.0	30.0	30.2	30.5
Coal, Coke and Coke Oven Gas	3.6	4.4	4.3	4.3	4.2	4.1	4.0	3.7	3.3	2.9
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	10.0	9.9	9.6	9.6	9.6	9.4	9.5	9.2	8.6	7.5
Other	0.6	0.5	0.6	0.7	0.8	0.8	0.9	1.1	1.3	1.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total End Use										
Electricity	32.2	34.0	34.5	34.7	35.1	33.2	33.9	36.8	38.8	40.5
Oil	47.4	43.6	43.0	42.5	41.6	41.6	40.5	37.4	35.1	33.3
Natural Gas	11.6	13.2	13.2	13.4	13.9	15.7	15.8	16.1	16.5	17.0
Coal, Coke and Coke Oven Gas	1.3	1.6	1.6	1.6	1.5	1.5	1.5	1.3	1.2	1.2
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5
Wood Waste	3.5	3.5	3.5	3.5	3.5	3.4	3.5	3.4	3.2	3.0
Other	1.6	1.7	1.8	1.9	1.9	2.1	2.3	2.5	2.6	2.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

(Percent)

Ontario

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Electricity	28.7	28.9	29.1	29.3	29.5	29.8	30.2	32.6	34.1	35.1
Oil	17.1	16.1	15.7	15.1	14.5	13.8	13.2	10.5	9.1	8.4
Natural Gas	45.7	46.5	46.6	47.0	47.4	47.7	47.9	48.0	47.8	47.4
Wood	5.5	5.5	5.5	5.5	5.5	5.5	5.5	5.6	5.6	5.6
Other	3.0	3.0	3.0	3.0	3.1	3.1	3.1	3.3	3.4	3.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Commercial										
Electricity	34.2	34.3	34.2	33.9	33.6	33.5	33.5	34.6	34.7	35.3
Oil	9.7	8.9	9.3	9.1	8.9	8.7	8.6	6.3	5.5	4.6
Natural Gas	54.8	55.4	55.0	55.4	55.8	55.9	56.0	56.6	56.2	56.4
Other	1.3	1.4	1.5	1.6	1.7	1.9	2.0	2.5	3.6	3.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Industrial										
Electricity	18.4	19.2	19.0	18.8	18.8	18.8	18.9	19.5	20.0	20.7
Oil	9.1	6.6	8.0	8.4	7.8	7.4	7.2	6.7	6.2	5.9
Natural Gas	35.0	35.8	34.5	35.0	36.6	37.5	38.1	39.5	40.4	41.3
Coal, Coke and Coke Oven Gas	25.2	26.8	27.4	27.2	26.5	26.3	26.0	25.7	25.4	24.8
Steam	4.5	4.0	3.8	3.6	3.5	3.3	3.1	2.3	2.1	2.0
Wood Waste	7.5	7.3	6.9	6.6	6.3	6.1	6.2	5.6	5.1	4.3
Other	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.8	1.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total End Use										
Electricity	16.6	16.7	16.8	16.9	17.0	17.1	17.1	17.9	18.5	19.2
Oil	38.4	37.3	36.9	35.9	34.6	34.1	34.1	33.2	32.1	30.5
Natural Gas	29.7	30.0	30.1	30.6	31.6	32.0	32.1	32.7	33.3	34.1
Coal, Coke and Coke Oven Gas	8.4	9.0	9.4	9.6	9.5	9.5	9.3	9.3	9.5	9.8
Steam	1.5	1.3	1.3	1.3	1.2	1.2	1.1	0.8	0.8	0.8
Wood	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9
Wood Waste	2.5	2.5	2.4	2.3	2.3	2.2	2.2	2.0	1.9	1.7
Other	1.9	2.0	2.1	2.5	2.8	2.9	3.0	3.0	3.1	3.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table A3-7 (Continued)
Distribution of End Use Demand by Fuel and Sector Canada and Regions

(Percent)	Ontario									
	High Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Electricity	28.7	28.9	29.3	29.8	30.3	31.0	31.8	36.1	38.4	39.8
Oil	17.1	16.1	15.3	14.5	13.7	12.8	11.9	7.7	5.3	4.0
Natural Gas	45.7	46.5	46.9	47.1	47.3	47.4	47.5	46.9	46.8	46.5
Wood	5.5	5.5	5.5	5.5	5.6	5.6	5.6	5.9	6.0	6.1
Other	3.0	3.0	3.0	3.1	3.1	3.1	3.2	3.3	3.5	3.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Commercial										
Electricity	34.2	34.3	34.3	34.2	34.2	34.4	34.6	36.0	36.3	36.9
Oil	9.7	8.9	9.1	8.9	8.7	8.5	8.3	5.9	4.9	4.0
Natural Gas	54.8	55.4	55.1	55.3	55.3	55.2	55.0	55.7	55.2	55.4
Other	1.3	1.4	1.5	1.6	1.7	1.9	2.0	2.5	3.7	3.7
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Industrial										
Electricity	18.4	19.2	19.0	18.8	18.9	19.0	19.2	20.4	21.3	22.3
Oil	9.1	6.6	7.7	8.1	7.5	7.0	6.7	5.8	5.4	5.1
Natural Gas	35.0	35.8	34.8	34.8	35.9	36.5	36.8	37.3	37.9	38.9
Coal, Coke and Coke Oven Gas	25.2	26.8	27.4	27.4	27.1	27.1	27.1	27.2	26.7	25.8
Steam	4.5	4.0	3.8	3.6	3.4	3.2	3.0	2.2	2.1	2.0
Wood Waste	7.5	7.3	7.0	6.8	6.6	6.5	6.7	6.4	5.8	5.0
Other	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.8	1.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total End Use										
Electricity	16.6	16.7	16.8	16.9	17.2	17.4	17.6	18.9	19.9	21.0
Oil	38.4	37.3	36.7	35.9	34.7	34.3	34.2	32.7	30.9	28.8
Natural Gas	29.7	30.0	30.2	30.4	31.1	31.3	31.2	31.4	32.1	33.1
Coal, Coke and Coke Oven Gas	8.4	9.0	9.4	9.5	9.5	9.6	9.5	9.6	9.7	10.0
Steam	1.5	1.3	1.3	1.2	1.2	1.1	1.1	0.8	0.8	0.8
Wood	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Wood Waste	2.5	2.5	2.4	2.4	2.3	2.3	2.3	2.2	2.1	1.9
Other	1.9	2.0	2.2	2.5	2.9	3.0	3.2	3.3	3.4	3.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

(Percent) **Manitoba**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Electricity	34.0	35.2	37.6	37.7	37.7	37.9	38.1	38.9	39.3	39.4
Oil	14.5	12.6	11.4	11.2	11.1	11.0	10.9	11.2	11.1	11.6
Natural Gas	43.0	44.2	42.9	43.1	43.3	43.4	43.3	42.2	41.7	41.1
Wood	5.4	5.4	5.6	5.6	5.5	5.5	5.5	5.5	5.5	5.5
Other	3.1	2.6	2.6	2.5	2.3	2.2	2.1	2.2	2.4	2.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Commercial										
Electricity	28.5	27.2	27.1	26.3	25.6	25.1	24.8	24.1	23.6	23.4
Oil	5.8	6.5	6.4	5.8	5.3	4.9	4.6	3.0	2.7	2.8
Natural Gas	62.1	62.2	62.1	63.2	64.1	64.8	65.2	65.8	64.8	63.7
Other	3.6	4.1	4.4	4.7	4.9	5.2	5.5	7.1	9.0	10.1
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Industrial										
Electricity	37.2	36.0	35.2	35.6	35.6	35.6	35.4	37.1	38.8	41.1
Oil	13.9	13.6	14.1	13.5	12.8	12.3	11.9	11.1	10.2	9.3
Natural Gas	25.4	25.0	25.3	26.3	27.1	27.6	28.0	30.1	31.0	31.5
Coal, Coke and Coke Oven Gas	5.9	5.5	5.5	5.5	5.5	5.4	5.3	5.2	5.1	4.9
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	16.4	18.7	18.7	17.8	17.6	17.6	17.9	14.7	13.0	11.0
Other	1.2	1.2	1.3	1.3	1.4	1.5	1.5	1.7	1.9	2.1
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total End Use										
Electricity	19.7	19.8	20.3	20.6	20.6	20.7	20.7	21.4	21.9	22.7
Oil	44.0	43.0	42.2	41.1	40.4	39.9	39.6	38.7	38.3	37.7
Natural Gas	29.6	30.1	30.1	30.8	31.3	31.6	31.8	31.9	31.6	31.4
Coal, Coke and Coke Oven Gas	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.4	1.4	1.5
Steam	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.4	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.2	1.2
Wood Waste	2.6	3.0	3.1	3.2	3.2	3.3	3.4	3.1	2.8	2.5
Other	1.4	1.4	1.4	1.5	1.5	1.6	1.6	2.0	2.4	2.7
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table A3-7 (Continued)
Distribution of End Use Demand by Fuel and Sector Canada and Regions

(Percent)	Manitoba									
	High Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Electricity	34.0	35.2	37.8	38.2	38.6	39.2	40.0	42.9	43.2	43.6
Oil	14.5	12.6	10.9	10.5	10.3	10.0	9.6	8.3	8.9	9.6
Natural Gas	43.0	44.2	43.2	43.2	43.2	43.0	42.7	40.9	39.9	38.8
Wood	5.4	5.4	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Other	3.1	2.6	2.6	2.5	2.4	2.2	2.1	2.3	2.4	2.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Commercial										
Electricity	28.5	27.2	27.2	26.7	26.3	26.1	25.8	25.8	25.7	25.6
Oil	5.8	6.5	6.2	5.7	5.3	4.9	4.6	3.1	2.7	2.8
Natural Gas	62.1	62.2	62.2	62.9	63.5	63.8	64.1	64.0	62.6	61.4
Other	3.6	4.1	4.4	4.7	4.9	5.2	5.5	7.1	9.1	10.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Industrial										
Electricity	37.2	36.0	35.1	35.7	35.9	36.0	35.9	38.5	40.5	42.9
Oil	13.9	13.6	13.6	13.1	12.6	12.2	11.8	11.3	10.3	9.3
Natural Gas	25.4	25.0	25.8	26.2	26.4	26.5	26.4	27.3	27.8	28.5
Coal, Coke and Coke Oven Gas	5.9	5.5	5.5	5.5	5.4	5.3	5.3	5.2	5.0	4.9
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	16.4	18.7	18.8	18.3	18.4	18.6	19.0	16.0	14.4	12.4
Other	1.2	1.2	1.2	1.3	1.4	1.5	1.5	1.7	1.9	2.1
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total End Use										
Electricity	19.7	19.8	20.4	20.7	20.9	21.1	21.3	22.9	23.7	24.8
Oil	44.0	43.0	41.9	41.0	40.4	40.0	39.6	38.1	37.4	36.5
Natural Gas	29.6	30.1	30.3	30.8	31.0	31.0	31.0	30.6	30.3	30.1
Coal, Coke and Coke Oven Gas	1.2	1.2	1.2	1.3	1.3	1.3	1.3	1.4	1.4	1.5
Steam	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Wood	1.4	1.4	1.4	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Wood Waste	2.6	3.0	3.1	3.2	3.3	3.4	3.5	3.3	3.1	2.8
Other	1.4	1.4	1.4	1.5	1.5	1.6	1.7	2.1	2.6	2.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

(Percent)

Saskatchewan

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Electricity	18.4	17.9	19.1	19.0	18.8	18.7	18.8	19.4	20.8	22.1
Oil	26.9	26.6	25.7	25.1	24.6	24.4	24.1	23.8	23.1	22.9
Natural Gas	49.7	50.2	49.8	50.5	51.2	51.5	51.8	51.6	51.0	50.1
Wood	2.2	2.1	2.1	2.1	2.1	2.1	2.0	2.0	1.9	1.8
Other	2.8	3.2	3.3	3.3	3.3	3.3	3.4	3.3	3.2	3.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Commercial										
Electricity	28.8	28.3	27.7	26.4	25.1	24.3	23.7	22.6	22.3	22.5
Oil	5.0	4.0	4.0	3.4	3.3	3.1	3.0	2.5	2.0	1.6
Natural Gas	63.4	64.9	65.6	67.4	68.8	69.8	70.5	72.0	72.7	72.9
Other	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.9	3.0	3.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Industrial										
Electricity	16.6	16.0	16.5	16.4	16.3	16.5	16.7	17.9	18.4	18.7
Oil	13.2	11.9	12.2	11.5	10.8	10.4	10.2	9.2	8.4	8.0
Natural Gas	51.2	52.5	52.2	53.5	54.7	55.6	56.2	57.0	59.0	60.7
Coal, Coke and Coke Oven Gas	5.4	5.8	5.7	5.6	5.5	5.5	5.4	4.8	4.2	3.6
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	12.1	12.4	12.0	11.5	11.2	10.5	10.1	9.8	8.6	7.5
Other	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.4	1.4	1.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total End Use										
Electricity	12.8	12.5	13.0	13.0	12.9	13.0	13.1	13.7	14.3	14.8
Oil	45.8	45.0	44.2	42.8	41.8	40.6	39.5	38.2	36.8	36.3
Natural Gas	34.5	35.3	35.6	36.9	38.1	39.2	40.1	41.1	42.3	43.0
Coal, Coke and Coke Oven Gas	1.5	1.6	1.6	1.7	1.7	1.7	1.7	1.6	1.4	1.2
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.4
Wood Waste	3.2	3.3	3.3	3.2	3.2	3.2	3.1	3.1	2.8	2.5
Other	1.6	1.7	1.7	1.8	1.8	1.8	1.9	1.9	1.8	1.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table A3-7 (Continued)
Distribution of End Use Demand by Fuel and Sector Canada and Regions

(Percent)	Saskatchewan									
	High Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Electricity	18.4	17.9	19.3	19.5	19.7	20.0	20.5	23.0	24.6	25.6
Oil	26.9	26.6	25.2	24.5	23.8	23.3	22.8	21.3	20.2	19.8
Natural Gas	49.7	50.2	50.1	50.6	51.1	51.2	51.3	50.2	49.8	49.2
Wood	2.2	2.1	2.2	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Other	2.8	3.2	3.3	3.3	3.4	3.4	3.4	3.4	3.3	3.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Commercial										
Electricity	28.8	28.3	27.8	26.8	26.0	25.5	25.1	24.7	24.9	25.2
Oil	5.0	4.0	3.8	3.4	3.3	3.1	3.0	2.5	2.0	1.6
Natural Gas	63.4	64.9	65.6	67.0	68.0	68.5	69.1	69.8	70.1	70.1
Other	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.9	3.0	3.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Industrial										
Electricity	16.6	16.0	16.5	16.7	17.0	17.4	17.9	19.9	21.1	21.6
Oil	13.2	11.9	11.8	11.4	11.0	10.8	10.7	10.2	8.8	8.0
Natural Gas	51.2	52.5	52.6	53.3	53.8	54.2	54.3	53.6	55.4	57.3
Coal, Coke and Coke Oven Gas	5.4	5.8	5.7	5.6	5.5	5.5	5.4	4.8	4.2	3.6
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	12.1	12.4	12.0	11.6	11.3	10.7	10.2	10.1	9.0	8.1
Other	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.4	1.4	1.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total End Use										
Electricity	12.8	12.5	13.1	13.2	13.4	13.7	14.0	15.5	16.5	17.1
Oil	45.8	45.0	43.8	42.7	41.7	40.6	39.6	38.0	36.0	35.0
Natural Gas	34.5	35.3	35.9	36.8	37.6	38.4	39.0	39.2	40.5	41.4
Coal, Coke and Coke Oven Gas	1.5	1.6	1.6	1.7	1.7	1.7	1.8	1.6	1.5	1.3
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5
Wood Waste	3.2	3.3	3.3	3.3	3.3	3.2	3.2	3.2	3.0	2.8
Other	1.6	1.7	1.8	1.8	1.8	1.9	1.9	2.0	2.0	2.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table A3-7 (Continued)
Distribution of End Use Demand by Fuel and Sector Canada and Regions

(Percent) — Alberta

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Electricity	12.2	12.3	12.5	12.7	12.8	13.0	13.2	14.0	14.6	14.8
Oil	8.9	8.5	7.9	7.7	7.7	7.7	7.7	8.5	8.9	9.3
Natural Gas	72.5	73.0	73.4	73.5	73.5	73.4	73.2	71.8	70.7	70.2
Wood	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5
Other	5.8	5.6	5.6	5.5	5.4	5.4	5.3	5.3	5.3	5.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Commercial										
Electricity	24.7	23.3	23.3	23.2	23.2	23.2	23.3	24.0	24.3	24.3
Oil	3.5	3.0	2.9	2.7	2.5	2.3	2.1	1.3	0.6	0.5
Natural Gas	68.1	70.7	70.9	71.1	71.4	71.5	71.5	71.3	71.6	71.7
Other	3.7	3.0	3.0	3.0	3.0	3.0	3.0	3.3	3.5	3.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Industrial										
Electricity	28.5	28.5	28.9	28.4	28.2	28.2	28.5	28.6	27.7	26.2
Oil	16.1	14.3	14.1	13.9	13.7	13.6	13.4	12.9	12.1	11.4
Natural Gas	45.5	47.9	47.3	47.7	48.0	48.1	47.9	46.8	48.2	50.5
Coal, Coke and Coke Oven Gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2	3.3	4.0	4.7
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	7.7	7.1	7.5	7.7	7.8	7.9	7.9	6.4	5.9	5.0
Other	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total End Use										
Electricity	9.8	9.7	9.6	9.4	9.4	9.4	9.5	10.4	10.5	10.8
Oil	30.8	30.1	29.9	29.6	29.5	29.4	29.2	27.9	27.1	27.0
Natural Gas	51.0	50.7	50.6	50.9	51.0	51.1	51.2	50.1	49.4	49.9
Coal, Coke and Coke Oven Gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.7	0.9	1.0
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood Waste	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.1	1.0
Other	6.9	8.1	8.4	8.7	8.6	8.6	8.6	9.6	10.9	10.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table A3-7 (Continued)
Distribution of End Use Demand by Fuel and Sector Canada and Regions

(Percent)	Alberta									
	High Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Electricity	12.2	12.3	12.5	12.8	13.1	13.4	13.7	15.0	15.7	16.0
Oil	8.9	8.5	7.9	7.5	7.4	7.4	7.4	7.8	8.3	8.5
Natural Gas	72.5	73.0	73.5	73.6	73.5	73.3	73.1	71.4	70.2	69.6
Wood	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5
Other	5.8	5.6	5.6	5.5	5.5	5.4	5.3	5.4	5.4	5.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Commercial										
Electricity	24.7	23.3	23.3	23.5	23.7	24.0	24.4	26.2	26.9	27.0
Oil	3.5	3.0	2.9	2.7	2.5	2.3	2.1	1.4	0.6	0.5
Natural Gas	68.1	70.7	70.9	70.8	70.8	70.7	70.5	69.2	68.9	68.9
Other	3.7	3.0	3.0	3.0	3.0	3.0	3.0	3.3	3.6	3.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Industrial										
Electricity	28.5	28.5	29.0	29.0	29.1	29.5	30.1	31.1	30.5	29.2
Oil	16.1	14.3	14.2	14.0	13.9	13.7	13.6	13.1	12.3	11.6
Natural Gas	45.5	47.9	47.5	47.6	47.7	47.5	47.2	45.0	46.1	48.1
Coal, Coke and Coke Oven Gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2	3.3	4.0	4.7
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	7.7	7.1	7.1	7.1	7.1	7.0	6.9	5.5	5.0	4.3
Other	2.0	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.2
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total End Use										
Electricity	9.8	9.7	9.8	9.8	9.9	10.1	10.4	11.8	12.2	12.5
Oil	30.8	30.1	29.8	29.3	29.2	29.0	28.8	27.3	26.3	26.0
Natural Gas	51.0	50.7	50.6	50.9	50.9	50.8	50.8	49.3	48.5	49.0
Coal, Coke and Coke Oven Gas	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.8	1.0	1.2
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Wood Waste	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.1	1.1	1.0
Other	6.9	8.1	8.4	8.6	8.6	8.6	8.6	9.6	10.9	10.3
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table A3-7 (Continued)
Distribution of End Use Demand by Fuel and Sector Canada and Regions

(Percent)	British Columbia and Territories									
	Low Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Electricity	32.0	32.9	34.2	33.9	33.5	33.3	33.5	34.1	34.5	35.1
Oil	14.0	12.0	11.0	10.3	9.9	9.5	9.2	7.7	7.0	5.9
Natural Gas	41.2	42.1	41.8	43.0	44.0	44.8	45.1	45.8	46.2	46.6
Wood	10.5	10.6	10.5	10.3	10.2	10.0	9.9	9.9	9.8	9.6
Other	2.3	2.5	2.5	2.4	2.4	2.3	2.3	2.4	2.5	2.6
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Commercial										
Electricity	33.1	33.9	35.0	34.9	34.8	34.9	35.0	36.9	38.8	39.9
Oil	18.7	16.9	17.2	17.6	17.9	18.1	18.1	15.2	11.2	8.7
Natural Gas	45.4	46.4	44.8	44.5	44.1	43.8	43.5	43.8	45.3	46.0
Other	2.8	2.8	2.9	3.0	3.1	3.3	3.4	4.0	4.7	5.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Industrial										
Electricity	21.2	20.6	21.1	20.7	21.0	21.1	21.3	21.1	21.6	21.9
Oil	15.5	14.4	14.5	14.4	13.9	13.4	13.0	11.6	11.3	11.0
Natural Gas	16.2	14.9	15.4	15.7	16.4	16.9	17.3	18.4	20.9	23.9
Coal, Coke and Coke Oven Gas	0.9	1.4	1.6	1.7	1.9	2.0	2.2	2.9	2.8	2.7
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	45.9	48.5	47.2	47.2	46.4	46.1	45.8	45.4	42.6	39.6
Other	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.6	0.8	0.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total End Use										
Electricity	18.1	18.2	18.7	18.4	18.5	18.6	18.8	19.0	19.5	19.9
Oil	37.4	35.2	34.8	34.4	34.1	33.6	33.3	31.9	31.0	30.4
Natural Gas	20.6	20.8	20.7	21.4	22.0	22.3	22.6	23.6	25.4	26.8
Coal, Coke and Coke Oven Gas	0.4	0.6	0.7	0.8	0.9	1.0	1.0	1.4	1.3	1.3
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	1.6	1.6	1.5	1.5	1.4	1.4	1.4	1.4	1.3	1.2
Wood Waste	20.9	22.6	22.4	22.4	22.0	21.9	21.7	21.3	19.9	18.6
Other	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.4	1.6	1.7
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table A3-7 (Continued)
Distribution of End Use Demand by Fuel and Sector Canada and Regions

(Percent)	British Columbia and Territories									
	High Price Case									
	1984	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Residential										
Electricity	32.0	32.9	34.3	34.3	34.2	34.3	34.6	36.3	36.9	37.2
Oil	14.0	12.0	10.6	9.7	9.1	8.5	7.8	4.9	3.4	3.3
Natural Gas	41.2	42.1	41.9	42.9	43.6	44.2	44.6	45.6	46.3	46.1
Wood	10.5	10.6	10.7	10.7	10.7	10.7	10.7	10.7	10.8	10.8
Other	2.3	2.5	2.5	2.4	2.4	2.4	2.3	2.4	2.6	2.7
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Commercial										
Electricity	33.1	33.9	35.1	35.2	35.4	35.7	36.1	39.2	41.8	43.1
Oil	18.7	16.9	17.0	17.4	17.6	17.8	17.8	14.6	10.4	7.8
Natural Gas	45.4	46.4	44.9	44.3	43.8	43.3	42.7	42.0	43.0	43.6
Other	2.8	2.8	2.9	3.0	3.1	3.3	3.4	4.1	4.8	5.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Industrial										
Electricity	21.2	20.6	21.0	20.4	20.7	20.8	20.9	20.7	20.9	21.0
Oil	15.5	14.4	14.2	14.1	13.5	12.9	12.5	11.0	10.4	10.0
Natural Gas	16.2	14.9	15.4	15.4	15.9	16.1	16.2	16.6	18.4	20.8
Coal, Coke and Coke Oven Gas	0.9	1.4	1.6	1.7	1.8	2.0	2.1	2.8	2.7	2.6
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood Waste	45.9	48.5	47.5	48.0	47.7	47.8	47.8	48.4	46.8	44.9
Other	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.6	0.7	0.8
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total End Use										
Electricity	18.1	18.2	18.7	18.4	18.5	18.7	18.8	19.4	19.9	20.3
Oil	37.4	35.2	34.5	34.1	33.6	33.1	32.7	30.7	29.2	28.4
Natural Gas	20.6	20.8	20.8	21.3	21.7	21.9	22.1	22.8	24.6	25.7
Coal, Coke and Coke Oven Gas	0.4	0.6	0.7	0.8	0.9	0.9	1.0	1.3	1.2	1.2
Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wood	1.6	1.6	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.4
Wood Waste	20.9	22.6	22.5	22.7	22.6	22.6	22.6	22.8	21.9	21.1
Other	1.0	1.1	1.1	1.1	1.2	1.2	1.3	1.5	1.7	1.9
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

($1986/Output Gigajoule) **Atlantic**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Light Fuel Oil	15.49	15.82	11.13	11.11	11.03	11.39	11.73	12.19	12.09	12.09
Electricity	15.52	15.76	16.04	16.19	16.31	16.31	16.31	16.31	16.31	16.31
Natural Gas	15.53	14.50	14.01	12.42	12.37	12.69	13.00	13.46	13.39	13.39
Commercial										
Light Fuel Oil	12.19	12.49	8.14	8.12	8.05	8.38	8.69	9.12	9.03	9.04
Heavy Fuel Oil	10.16	10.54	5.68	5.66	5.46	5.69	5.96	6.42	6.32	6.33
Electricity	22.59	21.26	21.64	21.85	22.02	22.02	22.02	22.02	22.02	22.02
Natural Gas	21.06	20.30	19.83	18.31	18.26	18.57	18.86	19.30	19.23	19.24
Industrial										
Heavy Fuel Oil	6.90	7.05	3.88	3.86	3.72	3.88	4.05	4.28	4.13	4.17
Electricity	14.05	12.83	13.35	13.43	13.52	13.52	13.49	13.24	12.96	13.09
Natural Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Light Fuel Oil	15.49	15.82	11.85	12.11	12.32	12.92	13.54	14.77	14.62	14.63
Electricity	15.52	15.76	16.07	16.19	16.27	16.27	16.27	16.27	16.27	16.27
Natural Gas	15.53	14.50	14.17	13.38	13.59	14.16	14.74	15.93	15.81	15.82
Commercial										
Light Fuel Oil	12.19	12.49	8.79	9.04	9.24	9.79	10.37	11.51	11.37	11.38
Heavy Fuel Oil	10.16	10.54	6.39	6.66	6.73	7.18	7.72	8.92	8.78	8.79
Electricity	22.59	21.26	21.69	21.85	21.96	21.96	21.96	21.96	21.96	21.96
Natural Gas	21.06	20.30	20.02	19.26	19.47	20.01	20.56	21.70	21.58	21.60
Industrial										
Heavy Fuel Oil	6.90	7.05	4.37	4.55	4.59	4.89	5.21	5.92	5.84	5.93
Electricity	14.05	12.83	13.38	13.48	13.50	13.47	13.36	13.14	13.18	13.37
Natural Gas	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Note: Fuel oils and natural gas prices have been adjusted for burner tip efficiencies.

In the September 1984 Report the electricity price for each sector was calculated as the ratio of revenue to electricity consumption, yielding an average electricity price per sector. In this report the residential price is the average value of the second to fifth 1000 kW.h of consumption on the residential tariff, while commercial and industrial electricity prices are derived from the capacity and energy charge applying to a representative monthly consumption for each sector.

Table A3-8 (Continued)
Real Average Retail Prices by Region and Sector

($1986/Output Gigajoule) **Quebec**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Light Fuel Oil	15.69	15.92	11.72	11.71	11.64	12.04	12.42	12.99	12.90	12.91
Electricity	11.75	11.52	11.84	11.84	11.84	11.84	11.84	11.84	11.84	11.84
Natural Gas	10.90	10.52	10.91	9.10	9.04	9.39	9.73	10.23	10.15	10.16
Commercial										
Light Fuel Oil	12.35	12.56	8.46	8.45	8.38	8.76	9.11	9.64	9.56	9.57
Heavy Fuel Oil	9.82	9.99	4.92	4.90	4.84	5.20	5.55	6.06	5.98	5.99
Electricity	13.96	14.19	14.58	14.58	14.58	14.58	14.58	14.58	14.58	14.58
Natural Gas	9.22	8.77	9.04	7.31	7.25	7.59	7.91	8.39	8.32	8.32
Industrial										
Heavy Fuel Oil	6.53	6.90	3.36	3.34	3.29	3.55	3.82	4.15	4.12	4.27
Electricity	8.83	8.28	8.42	8.39	8.37	8.40	8.47	8.43	8.47	8.77
Natural Gas	5.94	5.52	5.08	3.80	3.74	4.01	4.28	4.61	4.58	4.74

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Light Fuel Oil	15.69	15.92	12.53	12.85	13.12	13.81	14.53	15.99	15.84	15.86
Electricity	11.75	11.52	11.84	11.84	11.84	11.84	11.84	11.84	11.84	11.84
Natural Gas	10.90	10.52	11.06	10.12	10.35	10.97	11.60	12.90	12.77	12.78
Commercial										
Light Fuel Oil	12.35	12.56	9.20	9.49	9.74	10.39	11.06	12.41	12.27	12.29
Heavy Fuel Oil	9.82	9.99	5.62	5.90	6.14	6.77	7.42	8.73	8.60	8.61
Electricity	13.96	14.19	14.58	14.58	14.58	14.58	14.58	14.58	14.58	14.58
Natural Gas	9.22	8.77	9.17	8.27	8.50	9.09	9.69	10.93	10.80	10.82
Industrial										
Heavy Fuel Oil	6.53	6.90	3.84	4.03	4.17	4.60	5.06	5.90	5.87	6.08
Electricity	8.83	8.28	8.42	8.41	8.36	8.37	8.40	8.32	8.41	8.69
Natural Gas	5.94	5.52	5.17	4.50	4.64	5.08	5.53	6.39	6.36	6.58

Note: Fuel oils and natural gas prices have been adjusted for burner tip efficiencies.

In the September 1984 Report the electricity price for each sector was calculated as the ratio of revenue to electricity consumption, yielding an average electricity price per sector. In this report the residential price is the average value of the second to fifth 1000 kW.h of consumption on the residential tariff, while commercial and industrial electricity prices are derived from the capacity and energy charge applying to a representative monthly consumption for each sector.

($1986/Output Gigajoule) **Ontario**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Light Fuel Oil	15.20	15.45	10.25	10.24	10.17	10.54	10.90	11.42	11.34	11.34
Electricity	12.43	12.79	12.97	12.97	12.97	12.97	12.97	12.97	12.97	12.97
Natural Gas	9.49	9.19	8.68	6.99	6.93	7.26	7.57	8.03	7.95	7.96
Commercial										
Light Fuel Oil	11.96	12.20	7.37	7.35	7.29	7.64	7.97	8.45	8.37	8.38
Heavy Fuel Oil	9.54	9.99	4.88	4.86	4.80	5.16	5.51	6.02	5.94	5.95
Electricity	14.37	14.87	15.08	15.08	15.08	15.08	15.08	15.08	15.08	15.08
Natural Gas	7.63	7.31	6.82	5.21	5.16	5.47	5.76	6.20	6.13	6.14
Industrial										
Heavy Fuel Oil	6.84	6.90	3.33	3.31	3.26	3.52	3.79	4.12	4.11	4.29
Electricity	8.09	8.41	8.44	8.41	8.39	8.42	8.49	8.45	8.53	8.90
Natural Gas	5.47	5.04	4.60	3.30	3.25	3.51	3.78	4.11	4.09	4.27

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Light Fuel Oil	15.20	15.45	10.99	11.28	11.53	12.17	12.83	14.16	14.03	14.04
Electricity	12.43	12.79	12.97	12.97	12.97	12.97	12.97	12.97	12.97	12.97
Natural Gas	9.49	9.19	8.81	7.91	8.13	8.70	9.27	10.47	10.34	10.36
Commercial										
Light Fuel Oil	11.96	12.20	8.04	8.31	8.54	9.13	9.74	10.98	10.86	10.88
Heavy Fuel Oil	9.54	9.99	5.57	5.86	6.10	6.73	7.37	8.69	8.56	8.57
Electricity	14.37	14.87	15.08	15.08	15.08	15.08	15.08	15.08	15.08	15.08
Natural Gas	7.63	7.31	6.94	6.09	6.29	6.83	7.39	8.53	8.41	8.42
Industrial										
Heavy Fuel Oil	6.84	6.90	3.81	4.00	4.14	4.57	5.03	5.88	5.86	6.09
Electricity	8.09	8.41	8.44	8.43	8.37	8.39	8.41	8.35	8.45	8.76
Natural Gas	5.47	5.04	4.69	4.00	4.14	4.58	5.03	5.89	5.87	6.10

Note: Fuel oils and natural gas prices have been adjusted for burner tip efficiencies.

In the September 1984 Report the electricity price for each sector was calculated as the ratio of revenue to electricity consumption, yielding an average electricity price per sector. In this report the residential price is the average value of the second to fifth 1000 kW.h of consumption on the residential tariff, while commercial and industrial electricity prices are derived from the capacity and energy charge applying to a representative monthly consumption for each sector.

Table A3-8 (Continued)
Real Average Retail Prices by Region and Sector

($1986/Output Gigajoule)

Manitoba

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Light Fuel Oil	15.47	15.70	10.54	10.52	10.45	10.82	11.18	11.70	11.62	11.62
Electricity	9.08	9.25	9.27	9.51	9.69	9.78	9.83	10.03	10.03	10.03
Natural Gas	7.80	7.56	7.04	5.28	5.22	5.55	5.86	6.32	6.25	6.25
Commercial										
Light Fuel Oil	12.40	12.61	7.82	7.81	7.75	8.09	8.42	8.90	8.83	8.83
Heavy Fuel Oil	10.13	10.17	4.93	4.91	4.84	5.22	5.59	6.12	6.04	6.05
Electricity	13.58	13.02	13.05	13.38	13.63	13.77	13.84	14.12	14.12	14.12
Natural Gas	6.67	6.36	5.86	4.17	4.12	4.43	4.73	5.17	5.10	5.10
Industrial										
Heavy Fuel Oil	7.17	6.83	3.37	3.36	3.32	3.58	3.83	4.11	4.03	4.10
Electricity	7.80	7.06	7.20	7.39	7.53	7.61	7.66	7.66	7.61	7.74
Natural Gas	4.62	4.12	3.80	2.45	2.41	2.66	2.90	3.19	3.11	3.17

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Light Fuel Oil	15.47	15.70	11.28	11.57	11.81	12.45	13.11	14.44	14.31	14.33
Electricity	9.08	9.25	9.27	9.43	9.52	9.51	9.50	9.56	9.56	9.56
Natural Gas	7.80	7.56	7.16	6.20	6.41	6.98	7.56	8.75	8.63	8.64
Commercial										
Light Fuel Oil	12.40	12.61	8.50	8.77	8.99	9.59	10.20	11.44	11.32	11.33
Heavy Fuel Oil	10.13	10.17	5.65	5.95	6.20	6.86	7.54	8.91	8.77	8.79
Electricity	13.58	13.02	13.05	13.27	13.39	13.38	13.36	13.46	13.46	13.46
Natural Gas	6.67	6.36	5.97	5.05	5.25	5.79	6.35	7.49	7.37	7.38
Industrial										
Heavy Fuel Oil	7.17	6.83	3.87	4.07	4.22	4.65	5.09	5.86	5.80	5.96
Electricity	7.80	7.06	7.20	7.33	7.36	7.33	7.28	7.15	7.19	7.37
Natural Gas	4.62	4.12	3.88	3.14	3.29	3.71	4.13	4.90	4.84	4.97

Note: Fuel oils and natural gas prices have been adjusted for burner tip efficiencies.

In the September 1984 Report the electricity price for each sector was calculated as the ratio of revenue to electricity consumption, yielding an average electricity price per sector. In this report the residential price is the average value of the second to fifth 1000 kW.h of consumption on the residential tariff, while commercial and industrial electricity prices are derived from the capacity and energy charge applying to a representative monthly consumption for each sector.

($1986/Output Gigajoule) **Saskatchewan**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Light Fuel Oil	15.06	15.31	10.12	10.10	10.04	10.41	10.76	11.28	11.20	11.21
Electricity	12.71	13.75	14.41	15.13	15.78	15.78	15.78	15.78	15.78	15.78
Natural Gas	6.21	6.11	5.58	3.80	3.74	4.07	4.38	4.84	4.77	4.77
Commercial										
Light Fuel Oil	13.20	13.44	8.61	8.59	8.54	8.88	9.21	9.69	9.62	9.62
Heavy Fuel Oil	10.78	12.46	5.94	5.92	5.83	6.30	6.74	7.40	7.30	7.31
Electricity	21.80	23.62	24.76	26.00	27.12	27.12	27.12	27.12	27.12	27.12
Natural Gas	5.23	5.05	4.54	2.84	2.79	3.09	3.39	3.83	3.76	3.77
Industrial										
Heavy Fuel Oil	7.54	7.37	4.06	4.20	4.23	4.45	4.64	4.77	4.51	4.36
Electricity	11.76	12.19	14.77	16.12	17.16	16.72	16.26	15.25	14.63	14.10
Natural Gas	3.47	3.16	3.25	1.96	1.96	2.17	2.35	2.53	2.38	2.30

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Light Fuel Oil	15.06	15.31	10.86	11.15	11.39	12.03	12.69	14.03	13.89	13.91
Electricity	12.71	13.75	14.41	15.01	15.50	15.50	15.50	15.50	15.50	15.50
Natural Gas	6.21	6.11	5.70	4.71	4.93	5.49	6.07	7.26	7.14	7.15
Commercial										
Light Fuel Oil	13.20	13.44	9.29	9.56	9.79	10.38	10.99	12.23	12.11	12.12
Heavy Fuel Oil	10.78	12.46	6.82	7.19	7.50	8.30	9.13	10.80	10.64	10.66
Electricity	21.80	23.62	24.93	25.97	26.83	26.83	26.83	26.83	26.83	26.83
Natural Gas	5.23	5.05	4.65	3.70	3.91	4.45	5.00	6.14	6.02	6.04
Industrial										
Heavy Fuel Oil	7.54	7.37	4.67	5.01	5.23	5.59	5.96	6.44	6.32	6.31
Electricity	11.76	12.19	14.77	15.67	16.20	15.65	15.17	13.85	13.81	13.75
Natural Gas	3.47	3.16	3.33	2.63	2.80	3.13	3.46	3.95	3.86	3.85

Note: Fuel oils and natural gas prices have been adjusted for burner tip efficiencies.

In the September 1984 Report the electricity price for each sector was calculated as the ratio of revenue to electricity consumption, yielding an average electricity price per sector. In this report the residential price is the average value of the second to fifth 1000 kW.h of consumption on the residential tariff, while commercial and industrial electricity prices are derived from the capacity and energy charge applying to a representative monthly consumption for each sector.

Table A3-8 (Continued)
Real Average Retail Prices by Region and Sector

($1986/Output Gigajoule) — **Alberta**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Light Fuel Oil	13.91	14.26	9.10	9.08	9.01	9.38	9.74	10.26	10.18	10.18
Electricity	12.82	12.94	13.31	13.31	13.31	13.31	13.31	13.31	13.31	13.31
Natural Gas	5.58	5.61	5.40	4.86	4.80	5.13	5.44	5.90	5.83	5.83
Commercial										
Light Fuel Oil	12.11	12.44	7.64	7.63	7.57	7.91	8.24	8.72	8.65	8.65
Heavy Fuel Oil	9.15	11.49	5.46	5.43	5.36	5.79	6.21	6.82	6.72	6.73
Electricity	15.63	16.15	16.61	16.61	16.61	16.61	16.61	16.61	16.61	16.61
Natural Gas	4.10	4.10	3.89	3.37	3.32	3.63	3.93	4.37	4.30	4.30
Industrial										
Heavy Fuel Oil	6.21	6.58	3.73	3.94	3.95	4.12	4.17	4.33	4.11	4.08
Electricity	8.21	8.52	10.45	11.07	11.26	10.87	10.27	9.70	9.34	9.27
Natural Gas	2.04	2.16	2.41	2.12	2.11	2.29	2.40	2.59	2.45	2.43

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Light Fuel Oil	13.91	14.26	9.83	10.12	10.36	11.00	11.66	13.00	12.86	12.88
Electricity	12.82	12.94	13.33	13.33	13.33	13.33	13.33	13.33	13.33	13.33
Natural Gas	5.58	5.61	5.48	5.78	5.99	6.56	7.14	8.33	8.20	8.22
Commercial										
Light Fuel Oil	12.11	12.44	8.32	8.59	8.82	9.41	10.02	11.26	11.14	11.15
Heavy Fuel Oil	9.15	11.49	6.28	6.62	6.91	7.65	8.42	9.98	9.83	9.85
Electricity	15.63	16.15	16.63	16.63	16.63	16.63	16.63	16.63	16.63	16.63
Natural Gas	4.10	4.10	3.96	4.24	4.45	4.99	5.54	6.68	6.56	6.58
Industrial										
Heavy Fuel Oil	6.21	6.58	4.30	4.67	4.81	5.11	5.28	5.87	5.73	5.85
Electricity	8.21	8.52	10.47	10.79	10.67	10.22	9.60	9.00	8.93	9.10
Natural Gas	2.04	2.16	2.47	2.77	2.91	3.21	3.42	3.99	3.88	3.96

Note: Fuel oils and natural gas prices have been adjusted for burner tip efficiencies.

In the September 1984 Report the electricity price for each sector was calculated as the ratio of revenue to electricity consumption, yielding an average electricity price per sector. In this report the residential price is the average value of the second to fifth 1000 kW.h of consumption on the residential tariff, while commercial and industrial electricity prices are derived from the capacity and energy charge applying to a representative monthly consumption for each sector.

($1986/Output Gigajoule) **British Columbia and Territories**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Light Fuel Oil	14.90	15.15	9.86	9.84	9.78	10.15	10.50	11.02	10.94	10.95
Electricity	12.69	12.74	12.42	12.42	12.42	12.42	12.42	12.42	12.42	12.42
Natural Gas	7.39	7.27	6.49	5.75	5.70	5.99	6.27	6.67	6.61	6.62
Commercial										
Light Fuel Oil	11.72	11.95	7.05	7.03	6.97	7.31	7.64	8.13	8.05	8.06
Heavy Fuel Oil	8.55	8.88	4.26	4.25	4.19	4.51	4.82	5.28	5.21	5.21
Electricity	15.91	16.57	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15
Natural Gas	6.57	6.55	5.81	5.10	5.05	5.33	5.59	5.98	5.92	5.93
Industrial										
Heavy Fuel Oil	5.60	5.90	2.91	2.91	2.89	3.11	3.32	3.54	3.44	3.43
Electricity	8.33	8.87	8.91	8.94	8.98	8.97	8.95	8.74	8.59	8.56
Natural Gas	3.99	3.95	3.47	2.91	2.89	3.11	3.31	3.54	3.44	3.43

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Residential										
Light Fuel Oil	14.90	15.15	10.60	10.89	11.13	11.77	12.43	13.76	13.63	13.65
Electricity	12.69	12.74	12.42	12.42	12.42	12.42	12.42	12.42	12.42	12.42
Natural Gas	7.39	7.27	6.65	6.57	6.75	7.26	7.78	8.83	8.72	8.73
Commercial										
Light Fuel Oil	11.72	11.95	7.72	7.99	8.21	8.81	9.42	10.66	10.54	10.55
Heavy Fuel Oil	8.55	8.88	4.88	5.13	5.35	5.90	6.48	7.65	7.53	7.55
Electricity	15.91	16.57	16.15	16.15	16.15	16.15	16.15	16.15	16.15	16.15
Natural Gas	6.57	6.55	5.95	5.88	6.06	6.54	7.04	8.04	7.93	7.94
Industrial										
Heavy Fuel Oil	5.60	5.90	3.34	3.51	3.65	4.01	4.36	4.97	4.89	4.98
Electricity	8.33	8.87	8.91	8.92	8.90	8.85	8.76	8.46	8.45	8.59
Natural Gas	3.99	3.95	3.58	3.52	3.66	4.02	4.37	4.98	4.90	4.99

Note: Fuel oils and natural gas prices have been adjusted for burner tip efficiencies.

In the September 1984 Report the electricity price for each sector was calculated as the ratio of revenue to electricity consumption, yielding an average electricity price per sector. In this report the residential price is the average value of the second to fifth 1000 kW.h of consumption on the residential tariff, while commercial and industrial electricity prices are derived from the capacity and energy charge applying to a representative monthly consumption for each sector.

Appendix 4

Table A4-1
Electricity Demand Growth Rates - Canada and Regions

(Percent)

	1984-1990	1990-1995	1995-2000	2000-2005
Newfoundland				
Low Price Case	2.3	1.2	1.7	3.8
High Price Case	4.2	1.1	4.6	3.6
New Brunswick				
Low Price Case	3.7	3.6	3.6	3.6
High Price Case	3.1	3.8	2.6	3.3
Nova Scotia				
Low Price Case	2.6	3.4	3.7	3.6
High Price Case	2.2	3.5	3.1	3.3
Prince Edward Island				
Low Price Case	2.8	2.1	2.0	2.0
High Price Case	3.0	2.2	2.2	1.6
Quebec				
Low Price Case	2.6	2.5	2.4	2.7
High Price Case	2.2	2.5	2.3	2.5
Ontario				
Low Price Case	3.4	2.6	2.5	3.0
High Price Case	2.9	2.4	2.4	3.0
Manitoba				
Low Price Case	3.2	3.2	2.5	2.7
High Price Case	3.1	3.3	2.3	2.4
Saskatchewan				
Low Price Case	2.5	1.8	3.2	2.9
High Price Case	3.1	2.4	3.2	2.5
Alberta				
Low Price Case	1.5	3.1	2.0	2.0
High Price Case	3.1	4.1	2.4	2.0
British Columbia and Territories				
Low Price Case	2.9	1.1	2.3	2.4
High Price Case	2.3	0.8	1.9	1.8
Canada				
Low Price Case	2.8	2.5	2.5	2.8
High Price Case	2.6	2.4	2.4	2.6

Table A4-2
Historical Data - Total Demand for Electricity by Sector - Canada

(Petajoules)

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Residential	107.0	115.6	126.0	135.9	145.5	156.3	167.5	180.7	194.4	213.4
Commercial	85.9	96.9	104.0	114.6	130.1	143.0	156.0	186.7	205.0	223.2
Industrial	278.1	300.1	312.6	328.8	348.6	364.8	375.2	390.9	417.1	435.5
Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Own Use	47.8	51.1	54.1	57.0	57.9	64.1	66.2	75.1	80.6	89.9
Total	518.8	563.7	596.7	636.4	682.2	728.2	764.8	833.3	897.2	961.9

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Residential	230.8	254.8	275.7	310.3	315.4	333.6	342.3	357.4	374.9	393.0
Commercial	234.1	257.7	263.3	250.5	265.6	261.3	270.5	278.6	290.0	298.6
Industrial	392.0	405.8	447.7	470.1	476.7	503.9	523.9	490.4	513.2	576.6
Transportation	0.0	0.0	0.0	1.8	1.6	1.9	2.5	2.6	2.9	2.6
Own Use	100.2	106.8	92.6	107.0	103.7	114.9	107.3	113.9	112.9	119.3
Total	957.1	1025.0	1079.4	1139.7	1163.1	1215.6	1246.5	1242.9	1293.8	1390.2

Table A4-3
Total Demand for Electricity by Sector - Canada

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
(Gigawatt hours)										
Residential	109175.2	114130.3	117784.0	120617.7	124443.7	128009.3	131210.2	145316.8	159035.7	172072.1
Commercial	82941.4	85718.5	89581.9	92710.8	95294.5	97569.6	99588.1	114492.1	132258.8	153401.7
Industrial	160170.5	169819.3	178661.3	182878.0	187527.2	183483.0	186485.8	212088.7	242093.2	287958.0
Transportation	736.1	780.3	810.7	841.1	871.6	902.0	932.4	1084.6	1236.7	1388.9
Own Use	33134.7	34828.5	36985.0	37867.6	38297.7	38175.2	38339.0	42636.6	47759.8	54022.6
Total	386157.9	405276.8	423823.0	434915.2	446434.6	448139.1	456555.5	515618.8	582384.2	668843.3
(Petajoules)										
Residential	393.0	410.9	424.0	434.2	448.0	460.8	472.4	523.1	572.5	619.5
Commercial	298.6	308.6	322.5	333.8	343.1	351.3	358.5	412.2	476.1	552.2
Industrial	576.6	611.3	643.2	658.4	675.1	660.5	671.3	763.5	871.5	1036.6
Transportation	2.6	2.8	2.9	3.0	3.1	3.2	3.4	3.9	4.5	5.0
Own Use	119.3	125.4	133.1	136.3	137.9	137.4	138.0	153.5	171.9	194.5
Total	1390.2	1459.0	1525.8	1565.7	1607.2	1613.3	1643.6	1856.2	2096.6	2407.8

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
(Gigawatt hours)										
Residential	109175.2	114130.3	117858.3	120738.9	124525.0	128174.7	131460.8	147171.1	162519.7	176601.8
Commercial	82941.4	85718.5	89525.7	92236.5	94438.5	96395.7	98132.2	111093.6	127763.7	145919.4
Industrial	160170.5	169819.3	178507.8	180591.0	184096.4	179473.9	182463.6	206759.6	233899.3	273786.8
Transportation	736.1	780.3	921.8	1063.4	1204.9	1346.4	1488.0	2195.7	2903.4	3611.1
Own Use	33134.7	34828.5	37004.5	37727.1	38069.4	37915.5	38085.1	42363.1	47299.8	52877.1
Total	386157.9	405276.8	423818.2	432356.9	442334.2	443306.2	451629.6	509583.1	574386.0	652796.1
(Petajoules)										
Residential	393.0	410.9	424.3	434.7	448.3	461.4	473.3	529.8	585.1	635.8
Commercial	298.6	308.6	322.3	332.1	340.0	347.0	353.3	399.9	459.9	525.3
Industrial	576.6	611.3	642.6	650.1	662.7	646.1	656.9	744.3	842.0	985.6
Transportation	2.6	2.8	3.3	3.8	4.3	4.8	5.4	7.9	10.5	13.0
Own Use	119.3	125.4	133.2	135.8	137.0	136.5	137.1	152.5	170.3	190.4
Total	1390.2	1459.0	1525.7	1556.5	1592.4	1595.9	1625.9	1834.5	2067.8	2350.1

Table A4-4
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Gigawatts)

Canada
Low Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	16.1	16.8	16.9	16.9	17.5	18.0	19.1	20.4	23.7	28.7
Oil	3.7	3.6	3.6	3.6	3.6	3.1	2.8	2.9	4.6	4.6
Gas	2.8	2.8	2.8	2.8	2.6	2.6	2.6	2.7	2.5	2.5
Multi-fuelled	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	2.3	2.4	2.4	2.4	2.4	2.5	2.5	2.6	2.7	2.7
Other Fossil Fuelled										
Comb. Turbines	2.4	2.4	2.5	2.6	2.6	2.7	2.7	3.2	4.9	5.7
Int. Combustion	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.7
Nuclear	7.7	8.5	9.8	11.7	12.6	13.5	13.5	15.2	16.1	18.7
Hydro/Pumped Storage	55.0	56.7	56.8	56.8	56.9	57.1	58.4	66.4	73.3	81.5
Total Generating Capacity	90.4	93.7	95.3	97.3	98.8	99.9	102.0	114.0	128.4	145.1
Purchases[a]	5.1	5.4	5.4	5.4	5.4	5.4	5.4	5.3	5.4	5.4
Capacity Available	95.5	99.1	100.7	102.7	104.2	105.3	107.4	119.3	133.8	150.6
Sales (Export)	5.6	5.8	5.6	5.6	5.6	5.6	5.7	6.8	8.4	8.9
Domestic Peak Demand	72.6	74.3	77.1	79.2	81.3	81.5	82.6	92.8	104.5	119.1
System Peak	78.3	80.0	82.7	84.8	86.9	87.1	88.2	99.6	112.9	128.0
Remaining Capacity	17.2	19.1	18.0	17.9	17.2	18.2	19.2	19.7	20.9	22.5
% of System Peak	22.0	23.8	21.7	21.1	19.8	20.9	21.7	19.8	18.5	17.6

High Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	16.1	16.8	16.9	16.9	17.5	18.0	19.1	21.3	25.1	29.2
Oil	3.7	3.6	3.6	3.6	3.6	3.1	2.8	2.4	2.4	2.4
Gas	2.8	2.8	2.8	2.8	2.6	2.6	2.6	2.7	2.5	2.5
Multi-fuelled	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	2.3	2.4	2.4	2.4	2.4	2.5	2.5	2.6	2.7	2.7
Other Fossil Fuelled										
Comb. Turbines	2.4	2.4	2.6	2.6	2.7	2.7	2.9	3.4	4.9	6.1
Int. Combustion	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6
Nuclear	7.7	8.5	9.8	11.7	12.6	13.5	13.5	15.2	16.1	18.7
Hydro/Pumped Storage	55.0	56.7	56.8	56.8	56.9	57.1	58.4	66.4	69.8	77.2
Total Generating Capacity	90.4	93.7	95.3	97.3	98.8	99.9	102.2	114.5	124.1	139.5
Purchases[a]	5.1	5.4	5.4	5.4	5.4	5.4	5.4	5.3	5.4	5.4
Capacity Available	95.5	99.1	100.7	102.7	104.2	105.3	107.5	119.8	129.5	145.0
Sales (Export)	5.6	5.8	5.6	5.6	5.6	5.6	5.7	6.8	8.4	8.9
Domestic Peak Demand	72.6	74.2	77.1	78.7	80.5	80.1	81.2	91.2	101.8	114.8
System Peak	78.3	80.0	82.7	84.3	86.2	85.8	86.9	98.0	110.2	123.6
Remaining Capacity	17.2	19.1	18.0	18.3	18.0	19.5	20.7	21.8	19.3	21.3
% of System Peak	22.0	23.8	21.7	21.8	20.9	22.8	23.8	22.2	17.5	17.2

Note: [a] Includes imports and net capacity sales between provinces and capacity attributed to interconnected system.

(Megawatts)

Newfoundland
Low Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal										
Oil	505.0	505.0	505.0	505.0	505.0	505.0	505.0	505.0	510.0	510.0
Gas										
Multi-fuelled										
Other								5.0	10.0	15.0
Other Fossil Fuelled										
Comb. Turbines	170.0	170.0	170.0	170.0	170.0	170.0	170.0	270.0	270.0	270.0
Int. Combustion	81.0	81.0	81.0	81.0	81.0	81.0	81.0	78.0	78.0	78.0
Nuclear										
Hydro/Pumped Storage	6292.0	6419.0	6419.0	6419.0	6419.0	6419.0	6419.0	7268.0	8117.0	8117.0
Total Generating Capacity	7048.0	7175.0	7175.0	7175.0	7175.0	7175.0	7175.0	8126.0	8985.0	8990.0
Purchases[a]										
Capacity Available	7048.0	7175.0	7175.0	7175.0	7175.0	7175.0	7175.0	8126.0	8985.0	8990.0
Sales (Export)	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0
Domestic Peak Demand	1698.0	1833.0	1905.0	1914.0	1925.0	1903.0	1981.0	1996.0	2161.0	2577.0
System Peak	6448.0	6583.0	6655.0	6664.0	6675.0	6653.0	6731.0	6746.0	6911.0	7327.0
Remaining Capacity	600.0	592.0	520.0	511.0	500.0	522.0	444.0	1380.0	2074.0	1663.0
% of System Peak	9.3	9.0	7.8	7.7	7.5	7.8	6.6	20.5	30.0	22.7

High Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal										
Oil	505.0	505.0	505.0	505.0	505.0	505.0	505.0	505.0	510.0	510.0
Gas										
Multi-fuelled										
Other								5.0	10.0	15.0
Other Fossil Fuelled										
Comb. Turbines	170.0	170.0	170.0	170.0	170.0	220.0	320.0	370.0	370.0	370.0
Int. Combustion	81.0	81.0	81.0	81.0	81.0	81.0	81.0	78.0	78.0	78.0
Nuclear										
Hydro/Pumped Storage	6292.0	6419.0	6419.0	6419.0	6419.0	6419.0	6419.0	8117.0	8117.0	8117.0
Total Generating Capacity	7048.0	7175.0	7175.0	7175.0	7175.0	7225.0	7325.0	9075.0	9085.0	9090.0
Purchases[a]										
Capacity Available	7048.0	7175.0	7175.0	7175.0	7175.0	7225.0	7325.0	9075.0	9085.0	9090.0
Sales (Export)	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0
Domestic Peak Demand	1698.0	1833.0	1921.0	1949.0	2034.0	2062.0	2201.0	2210.0	2735.0	3238.0
System Peak	6448.0	6583.0	6671.0	6699.0	6784.0	6812.0	6951.0	6960.0	7485.0	7988.0
Remaining Capacity	600.0	592.0	504.0	476.0	391.0	413.0	374.0	2115.0	1600.0	1102.0
% of System Peak	9.3	9.0	7.6	7.1	5.8	6.1	5.4	30.4	21.4	13.8

Note: [a] Includes imports and net capacity sales between provinces and capacity attributed to interconnected system.

Table A4-4 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts)

Nova Scotia
Low Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	718.0	861.0	861.0	861.0	861.0	1018.0	1018.0	1168.0	1318.0	1918.0
Oil	779.0	698.0	698.0	698.0	698.0	553.0	553.0	528.0	518.0	518.0
Gas								25.0	35.0	35.0
Multi-fuelled										
Other	22.0	22.0	22.0	22.0	22.0	22.0	22.0	27.0	32.0	32.0
Other Fossil Fuelled										
Comb. Turbines	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	325.0	385.0
Int. Combustion	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Nuclear										
Hydro/Pumped Storage	386.0	386.0	386.0	386.0	386.0	386.0	386.0	386.0	386.0	386.0
Total Generating Capacity	2111.0	2173.0	2173.0	2173.0	2173.0	2185.0	2185.0	2340.0	2615.0	3275.0
Purchases[a]										
Capacity Available	2111.0	2173.0	2173.0	2173.0	2173.0	2185.0	2185.0	2340.0	2615.0	3275.0
Sales (Export)										
Domestic Peak Demand	1388.0	1485.0	1528.0	1546.0	1549.0	1586.0	1598.0	1890.0	2259.0	2687.0
System Peak	1388.0	1485.0	1528.0	1546.0	1549.0	1586.0	1598.0	1890.0	2259.0	2687.0
Remaining Capacity	723.0	688.0	645.0	627.0	624.0	599.0	587.0	450.0	356.0	588.0
% of System Peak	52.1	46.3	42.2	40.6	40.3	37.8	36.7	23.8	15.8	21.9

High Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	718.0	861.0	861.0	861.0	861.0	1018.0	1018.0	1018.0	1168.0	1618.0
Oil	779.0	698.0	698.0	698.0	698.0	553.0	553.0	528.0	518.0	518.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	25.0	35.0	35.0
Multi-fuelled										
Other	22.0	22.0	22.0	22.0	22.0	22.0	22.0	27.0	32.0	32.0
Other Fossil Fuelled										
Comb. Turbines	205.0	205.0	205.0	205.0	205.0	205.0	205.0	205.0	265.0	325.0
Int. Combustion	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Nuclear										
Hydro/Pumped Storage	386.0	386.0	386.0	386.0	386.0	386.0	386.0	386.0	386.0	386.0
Total Generating Capacity	2111.0	2173.0	2173.0	2173.0	2173.0	2185.0	2185.0	2190.0	2405.0	2915.0
Purchases[a]										
Capacity Available	2111.0	2173.0	2173.0	2173.0	2173.0	2185.0	2185.0	2190.0	2405.0	2915.0
Sales (Export)										
Domestic Peak Demand	1388.0	1485.0	1524.0	1533.0	1524.0	1530.0	1532.0	1817.0	2079.0	2438.0
System Peak	1388.0	1485.0	1524.0	1533.0	1524.0	1530.0	1532.0	1817.0	2079.0	2438.0
Remaining Capacity	723.0	688.0	649.0	640.0	649.0	655.0	653.0	373.0	326.0	477.0
% of System Peak	52.1	46.3	42.6	41.7	42.6	42.8	42.6	20.5	15.7	19.6

Note: [a] Includes imports and net capacity sales between provinces and capacity attributed to interconnected system.

(Megawatts)

Prince Edward Island
Low Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal										
Oil	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0
Gas										
Multi-fuelled										
Other										
Other Fossil Fuelled										
Comb. Turbines	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0
Int. Combustion	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Nuclear										
Hydro/Pumped Storage										
Total Generating Capacity	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0
Purchases[a]	20.0	20.0	20.0	20.0	20.0	20.0	35.0	50.0	65.0	80.0
Capacity Available	143.0	143.0	143.0	143.0	143.0	143.0	158.0	173.0	188.0	203.0
Sales (Export)										
Domestic Peak Demand	103.0	110.0	114.0	118.0	120.0	122.0	126.0	139.0	152.0	167.0
System Peak	103.0	110.0	114.0	118.0	120.0	122.0	126.0	139.0	152.0	167.0
Remaining Capacity	40.0	33.0	29.0	25.0	23.0	21.0	32.0	34.0	36.0	36.0
% of System Peak	38.8	30.0	25.4	21.2	19.2	17.2	25.4	24.5	23.7	21.6

High Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal										
Oil	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0
Gas										
Multi-fuelled										
Other										
Other Fossil Fuelled										
Comb. Turbines	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0	41.0
Int. Combustion	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
Nuclear										
Hydro/Pumped Storage										
Total Generating Capacity	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0	123.0
Purchases[a]	20.0	20.0	20.0	20.0	20.0	20.0	35.0	50.0	65.0	80.0
Capacity Available	143.0	143.0	143.0	143.0	143.0	143.0	158.0	173.0	188.0	203.0
Sales (Export)										
Domestic Peak Demand	103.0	110.0	114.0	116.0	120.0	122.0	126.0	141.0	156.0	169.0
System Peak	103.0	110.0	114.0	116.0	120.0	122.0	126.0	141.0	156.0	169.0
Remaining Capacity	40.0	33.0	29.0	27.0	23.0	21.0	32.0	32.0	32.0	34.0
% of System Peak	38.8	30.0	25.4	23.3	19.2	17.2	25.4	22.7	20.5	20.1

Note: [a] Includes imports and net capacity sales between provinces and capacity attributed to interconnected system.

Table A4-4 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts) — **New Brunswick** — **Low Price Case**

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	283.0	283.0	305.0	305.0	305.0	640.0	975.0	1810.0	2410.0	3010.0
Oil	1476.0	1474.0	1474.0	1464.0	1464.0	1129.0	794.0	416.0	416.0	416.0
Gas								43.0	43.0	43.0
Multi-fuelled										
Other	40.0	61.0	61.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0
Other Fossil Fuelled										
Comb. Turbines	25.0	25.0	25.0	25.0	25.0	25.0	75.0	275.0	425.0	675.0
Int. Combustion	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Nuclear	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0
Hydro/Pumped Storage	897.0	897.0	902.0	902.0	902.0	902.0	902.0	902.0	902.0	902.0
Total Generating Capacity	3352.0	3371.0	3398.0	3398.0	3398.0	3398.0	3448.0	4148.0	4898.0	5748.0
Purchases[a]										
Capacity Available	3352.0	3371.0	3398.0	3398.0	3398.0	3398.0	3448.0	4148.0	4898.0	5748.0
Sales (Export)	383.0	383.0	250.0	250.0	250.0	250.0	265.0	530.0	545.0	560.0
Domestic Peak Demand	1989.0	2060.0	2255.0	2384.0	2457.0	2541.0	2571.0	3048.0	3607.0	4291.0
System Peak	2372.0	2443.0	2505.0	2634.0	2707.0	2791.0	2836.0	3578.0	4152.0	4851.0
Remaining Capacity	980.0	928.0	893.0	764.0	691.0	607.0	612.0	570.0	746.0	897.0
% of System Peak	41.3	38.0	35.6	29.0	25.5	21.7	21.6	15.9	18.0	18.5

High Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	283.0	283.0	305.0	305.0	305.0	625.0	975.0	1810.0	2110.0	2710.0
Oil	1476.0	1474.0	1474.0	1464.0	1464.0	1129.0	794.0	416.0	416.0	416.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0	43.0	43.0
Multi-fuelled										
Other	40.0	61.0	61.0	71.0	71.0	71.0	71.0	71.0	71.0	71.0
Other Fossil Fuelled										
Comb. Turbines	25.0	25.0	25.0	25.0	25.0	25.0	75.0	225.0	325.0	525.0
Int. Combustion	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Nuclear	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0
Hydro/Pumped Storage	897.0	897.0	902.0	902.0	902.0	902.0	902.0	902.0	902.0	902.0
Total Generating Capacity	3352.0	3371.0	3398.0	3398.0	3398.0	3383.0	3448.0	4098.0	4498.0	5298.0
Purchases[a]										
Capacity Available	3352.0	3371.0	3398.0	3398.0	3398.0	3383.0	3448.0	4098.0	4498.0	5298.0
Sales (Export)	383.0	383.0	250.0	250.0	250.0	250.0	265.0	530.0	545.0	560.0
Domestic Peak Demand	1989.0	2062.0	2249.0	2367.0	2412.0	2474.0	2485.0	2970.0	3309.0	3872.0
System Peak	2372.0	2445.0	2499.0	2617.0	2662.0	2724.0	2750.0	3500.0	3854.0	4432.0
Remaining Capacity	980.0	926.0	899.0	781.0	736.0	659.0	698.0	598.0	644.0	866.0
% of System Peak	41.3	37.9	36.0	29.8	27.6	24.2	25.4	17.1	16.7	19.5

Note: [a] Includes imports and net capacity sales between provinces and capacity attributed to interconnected system.

(Megawatts)

Atlantic
Low Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	1001.0	1144.0	1166.0	1166.0	1166.0	1658.0	1993.0	2978.0	3728.0	4928.0
Oil	2831.0	2748.0	2748.0	2738.0	2738.0	2258.0	1923.0	1520.0	1515.0	1515.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	68.0	78.0	78.0
Multi-fuelled	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	62.0	83.0	83.0	93.0	93.0	93.0	93.0	103.0	113.0	118.0
Other Fossil Fuelled										
Comb. Turbines	441.0	441.0	441.0	441.0	441.0	441.0	491.0	791.0	1061.0	1371.0
Int. Combustion	94.0	94.0	94.0	94.0	94.0	94.0	94.0	91.0	91.0	91.0
Nuclear	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0
Hydro/Pumped Storage	7575.0	7702.0	7707.0	7707.0	7707.0	7707.0	7707.0	8556.0	9405.0	9405.0
Total Generating Capacity	12634.0	12842.0	12869.0	12869.0	12869.0	12881.0	12931.0	14737.0	16621.0	18136.0
Purchases[a]	20.0	20.0	20.0	20.0	20.0	20.0	35.0	50.0	65.0	80.0
Capacity Available	12654.0	12862.0	12889.0	12889.0	12889.0	12901.0	12966.0	14787.0	16686.0	18216.0
Sales (Export)	5133.0	5133.0	5000.0	5000.0	5000.0	5000.0	5015.0	5280.0	5295.0	5310.0
Domestic Peak Demand	5178.0	5488.0	5802.0	5962.0	6051.0	6152.0	6276.0	7073.0	8179.0	9722.0
System Peak	10311.0	10621.0	10802.0	10962.0	11051.0	11152.0	11291.0	12353.0	13474.0	15032.0
Remaining Capacity	2343.0	2241.0	2087.0	1927.0	1838.0	1749.0	1675.0	2434.0	3212.0	3184.0
% of System Peak	22.7	21.1	19.3	17.6	16.6	15.7	14.8	19.7	23.8	21.2

High Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	1001.0	1144.0	1166.0	1166.0	1166.0	1643.0	1993.0	2828.0	3278.0	4328.0
Oil	2831.0	2748.0	2748.0	2738.0	2738.0	2258.0	1923.0	1520.0	1515.0	1515.0
Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	68.0	78.0	78.0
Multi-fuelled	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	62.0	83.0	83.0	93.0	93.0	93.0	93.0	103.0	113.0	118.0
Other Fossil Fuelled										
Comb. Turbines	441.0	441.0	441.0	441.0	441.0	491.0	641.0	841.0	1001.0	1261.0
Int. Combustion	94.0	94.0	94.0	94.0	94.0	94.0	94.0	91.0	91.0	91.0
Nuclear	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0
Hydro/Pumped Storage	7575.0	7702.0	7707.0	7707.0	7707.0	7707.0	7707.0	9405.0	9405.0	9405.0
Total Generating Capacity	12634.0	12842.0	12869.0	12869.0	12869.0	12916.0	13081.0	15486.0	16111.0	17426.0
Purchases[a]	20.0	20.0	20.0	20.0	20.0	20.0	35.0	50.0	65.0	80.0
Capacity Available	12654.0	12862.0	12889.0	12889.0	12889.0	12936.0	13116.0	15536.0	16176.0	17506.0
Sales (Export)	5133.0	5133.0	5000.0	5000.0	5000.0	5000.0	5015.0	5280.0	5295.0	5310.0
Domestic Peak Demand	5178.0	5490.0	5808.0	5965.0	6090.0	6188.0	6344.0	7138.0	8279.0	9717.0
System Peak	10311.0	10623.0	10808.0	10965.0	11090.0	11188.0	11359.0	12418.0	13574.0	15027.0
Remaining Capacity	2343.0	2239.0	2081.0	1924.0	1799.0	1748.0	1757.0	3118.0	2602.0	2479.0
% of System Peak	22.7	21.1	19.3	17.5	16.2	15.6	15.5	25.1	19.2	16.5

Note: [a] Includes imports and net capacity sales between provinces and capacity attributed to interconnected system.

Table A4-4 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts)

Quebec
Low Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal										
Oil	638.0	638.0	630.0	630.0	620.0	620.0	620.0	620.0	620.0	620.0
Gas										
Multi-fuelled										
Other			10.0	10.0	20.0	20.0	20.0	20.0	20.0	20.0
Other Fossil Fuelled										
Comb. Turbines	364.0	364.0	424.0	424.0	424.0	424.0	424.0	424.0	1624.0	1624.0
Int. Combustion	65.0	71.0	71.0	88.0	88.0	88.0	88.0	130.0	178.0	202.0
Nuclear	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0
Hydro/Pumped Storage	24060.0	25333.0	25419.0	25480.0	25539.0	25582.0	26562.0	30636.0	34446.0	40956.0
Total Generating Capacity	25757.0	27036.0	27184.0	27262.0	27321.0	27364.0	28344.0	32460.0	37518.0	44052.0
Purchases[a]	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0
Capacity Available	30507.0	31786.0	31934.0	32012.0	32071.0	32114.0	33094.0	37210.0	42268.0	48802.0
Sales (Export)	0.0	150.0	200.0	200.0	200.0	200.0	200.0	200.0	1200.0	1700.0
Domestic Peak Demand	26761.0	26935.0	27638.0	28350.0	29046.0	27994.0	28656.0	32640.0	36968.0	42454.0
System Peak	26761.0	27085.0	27838.0	28550.0	29246.0	28194.0	28856.0	32840.0	38168.0	44154.0
Remaining Capacity	3746.0	4701.0	4096.0	3462.0	2825.0	3920.0	4238.0	4370.0	4100.0	4648.0
% of System Peak	14.0	17.4	14.7	12.1	9.7	13.9	14.7	13.3	10.7	10.5
High Price Case										
Fossil Fuelled Steam										
Coal										
Oil	638.0	638.0	630.0	630.0	620.0	620.0	620.0	620.0	620.0	620.0
Gas										
Multi-fuelled										
Other	0.0	0.0	10.0	10.0	20.0	20.0	20.0	20.0	20.0	20.0
Other Fossil Fuelled										
Comb. Turbines	364.0	364.0	424.0	424.0	424.0	424.0	424.0	424.0	1424.0	1624.0
Int. Combustion	65.0	71.0	71.0	88.0	88.0	88.0	88.0	130.0	178.0	202.0
Nuclear	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0	630.0
Hydro/Pumped Storage	24060.0	25333.0	25419.0	25480.0	25539.0	25582.0	26562.0	30636.0	32221.0	38006.0
Total Generating Capacity	25757.0	27036.0	27184.0	27262.0	27321.0	27364.0	28344.0	32460.0	35093.0	41102.0
Purchases[a]	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0	4750.0
Capacity Available	30507.0	31786.0	31934.0	32012.0	32071.0	32114.0	33094.0	37210.0	39843.0	45852.0
Sales (Export)	0.0	150.0	200.0	200.0	200.0	200.0	200.0	200.0	1200.0	1700.0
Domestic Peak Demand	26761.0	26935.0	27575.0	28070.0	28612.0	27071.0	27672.0	31381.0	34873.0	39636.0
System Peak	26761.0	27085.0	27775.0	28270.0	28812.0	27271.0	27872.0	31581.0	36073.0	41336.0
Remaining Capacity	3746.0	4701.0	4159.0	3742.0	3259.0	4843.0	5222.0	5629.0	3770.0	4516.0
% of System Peak	14.0	17.4	15.0	13.2	11.3	17.8	18.7	17.8	10.5	10.9

Note: [a] Includes imports and net capacity sales between provinces and capacity attributed to interconnected system.

Table A4-4 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts)

Ontario
Low Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	8690.0	8896.0	8896.0	8896.0	9102.0	9102.0	9190.0	9190.0	11102.0	13102.0
Oil	55.0	55.0	55.0	55.0	55.0	70.0	70.0	628.0	2332.0	2332.0
Gas	165.0	165.0	165.0	165.0	180.0	180.0	180.0	200.0	220.0	220.0
Multi-fuelled										
Other	1935.0	1940.0	1940.0	1940.0	1940.0	1940.0	1950.0	1960.0	1960.0	1970.0
Other Fossil Fuelled										
Comb. Turbines	729.0	781.0	788.0	798.0	798.0	808.0	808.0	818.0	918.0	1218.0
Int. Combustion	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Nuclear	6395.0	7230.0	8581.0	10446.0	11327.0	12208.0	12208.0	13970.0	14829.0	17472.0
Hydro/Pumped Storage	7185.0	7185.0	7185.0	7185.0	7185.0	7185.0	7185.0	8062.0	8062.0	8062.0
Total Generating Capacity	25164.0	26262.0	27620.0	29495.0	30597.0	31503.0	31601.0	34838.0	39433.0	44386.0
Purchases[a]										
Capacity Available	25164.0	26262.0	27620.0	29495.0	30597.0	31503.0	31601.0	34838.0	39433.0	44386.0
Sales (Export)	465.0	472.0	435.0	435.0	435.0	435.0	435.0			
Domestic Peak Demand	21379.0	21740.0	22625.0	23446.0	24416.0	25153.0	25105.0	28099.0	31280.0	35305.0
System Peak	21844.0	22212.0	23060.0	23881.0	24851.0	25588.0	25540.0	28099.0	31280.0	35305.0
Remaining Capacity	3320.0	4050.0	4560.0	5614.0	5746.0	5915.0	6061.0	6739.0	8153.0	9081.0
% of System Peak	15.2	18.2	19.8	23.5	23.1	23.1	23.7	24.0	26.1	25.7

High Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	8690.0	8896.0	8896.0	8896.0	9102.0	9102.0	9190.0	9190.0	11102.0	12602.0
Oil	55.0	55.0	55.0	55.0	55.0	70.0	70.0	70.0	100.0	100.0
Gas	165.0	165.0	165.0	165.0	180.0	180.0	180.0	200.0	220.0	220.0
Multi-fuelled										
Other	1935.0	1940.0	1940.0	1940.0	1940.0	1940.0	1950.0	1960.0	1960.0	1970.0
Other Fossil Fuelled										
Comb. Turbines	729.0	781.0	788.0	798.0	798.0	808.0	808.0	818.0	918.0	1218.0
Int. Combustion	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Nuclear	6395.0	7230.0	8581.0	10446.0	11327.0	12208.0	12208.0	13970.0	14829.0	17472.0
Hydro/Pumped Storage	7185.0	7185.0	7185.0	7185.0	7185.0	7185.0	7185.0	7185.0	8062.0	8062.0
Total Generating Capacity	25164.0	26262.0	27620.0	29495.0	30597.0	31503.0	31601.0	33403.0	37201.0	41654.0
Purchases[a]										
Capacity Available	25164.0	26262.0	27620.0	29495.0	30597.0	31503.0	31601.0	33403.0	37201.0	41654.0
Sales (Export)	465.0	472.0	435.0	435.0	435.0	435.0	435.0	0.0	0.0	0.0
Domestic Peak Demand	21379.0	21740.0	22587.0	23132.0	23878.0	24469.0	24365.0	26953.0	29906.0	33601.0
System Peak	21844.0	22212.0	23022.0	23567.0	24313.0	24904.0	24800.0	26953.0	29906.0	33601.0
Remaining Capacity	3320.0	4050.0	4598.0	5928.0	6284.0	6599.0	6801.0	6450.0	7295.0	8053.0
% of System Peak	15.2	18.2	20.0	25.2	25.8	26.5	27.4	23.9	24.4	24.0

Note: [a] Includes imports and net capacity sales between provinces and capacity attributed to interconnected system.

Table A4-4 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts)

Manitoba
Low Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	369.0	369.0	369.0	369.0	369.0	369.0	369.0	369.0	369.0	633.0
Oil	15.0	15.0	15.0	15.0	15.0	15.0	10.0	10.0	10.0	10.0
Gas	54.0	54.0	54.0	54.0	54.0	54.0	59.0	59.0	59.0	59.0
Multi-fuelled										
Other	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Other Fossil Fuelled										
Comb. Turbines	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	43.0
Int. Combustion	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Nuclear										
Hydro/Pumped Storage	3548.0	3548.0	3548.0	3548.0	3548.0	3676.0	4060.0	5218.0	6128.0	6478.0
Total Generating Capacity	4042.0	4042.0	4042.0	4042.0	4042.0	4170.0	4554.0	5712.0	6622.0	7261.0
Purchases[a]	300.0	300.0	300.0	300.0	300.0	300.0	300.0	200.0	300.0	300.0
Capacity Available	4342.0	4342.0	4342.0	4342.0	4342.0	4470.0	4854.0	5912.0	6922.0	7561.0
Sales (Export)								500.0	1050.0	1050.0
Domestic Peak Demand	2829.0	3052.0	3241.0	3502.0	3643.0	3721.0	3776.0	4418.0	4991.0	5704.0
System Peak	2829.0	3052.0	3241.0	3502.0	3643.0	3721.0	3776.0	4918.0	6041.0	6754.0
Remaining Capacity	1513.0	1290.0	1101.0	840.0	699.0	749.0	1078.0	994.0	881.0	807.0
% of System Peak	53.5	42.3	34.0	24.0	19.2	20.1	28.5	20.2	14.6	11.9

High Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	369.0	369.0	369.0	369.0	369.0	369.0	369.0	369.0	369.0	435.0
Oil	15.0	15.0	15.0	15.0	15.0	15.0	10.0	10.0	10.0	10.0
Gas	54.0	54.0	54.0	54.0	54.0	54.0	59.0	59.0	59.0	59.0
Multi-fuelled										
Other	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Other Fossil Fuelled										
Comb. Turbines	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	43.0
Int. Combustion	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Nuclear										
Hydro/Pumped Storage	3548.0	3548.0	3548.0	3548.0	3548.0	3676.0	4060.0	5218.0	6128.0	6478.0
Total Generating Capacity	4042.0	4042.0	4042.0	4042.0	4042.0	4170.0	4554.0	5712.0	6622.0	7063.0
Purchases[a]	300.0	300.0	300.0	300.0	300.0	300.0	300.0	200.0	300.0	300.0
Capacity Available	4342.0	4342.0	4342.0	4342.0	4342.0	4470.0	4854.0	5912.0	6922.0	7363.0
Sales (Export)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	500.0	1050.0	1050.0
Domestic Peak Demand	2829.0	3052.0	3237.0	3474.0	3604.0	3684.0	3737.0	4363.0	4884.0	5508.0
System Peak	2829.0	3052.0	3237.0	3474.0	3604.0	3684.0	3737.0	4863.0	5934.0	6558.0
Remaining Capacity	1513.0	1290.0	1105.0	868.0	738.0	786.0	1117.0	1049.0	988.0	805.0
% of System Peak	53.5	42.3	34.1	25.0	20.5	21.3	29.9	21.6	16.6	12.3

Note: [a] Includes imports and net capacity sales between provinces and capacity attributed to interconnected system.

(Megawatts)

Saskatchewan
Low Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	1595.0	1595.0	1595.0	1595.0	1595.0	1595.0	1895.0	1895.0	2195.0	2795.0
Oil	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Gas	131.0	131.0	131.0	131.0	131.0	131.0	131.0	131.0	131.0	131.0
Multi-fuelled										
Other	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
Other Fossil Fuelled										
Comb. Turbines	157.0	157.0	242.0	242.0	327.0	327.0	327.0	327.0	512.0	512.0
Int. Combustion										
Nuclear										
Hydro/Pumped Storage	589.0	841.0	841.0	841.0	841.0	841.0	841.0	841.0	841.0	841.0
Total Generating Capacity	2515.0	2767.0	2852.0	2852.0	2937.0	2937.0	3237.0	3237.0	3722.0	4322.0
Purchases[a]										
Capacity Available	2515.0	2767.0	2852.0	2852.0	2937.0	2937.0	3237.0	3237.0	3722.0	4322.0
Sales (Export)	7.0									
Domestic Peak Demand	2278.0	2301.0	2400.0	2438.0	2461.0	2537.0	2625.0	2861.0	3348.0	3850.0
System Peak	2285.0	2301.0	2400.0	2438.0	2461.0	2537.0	2625.0	2861.0	3348.0	3850.0
Remaining Capacity	230.0	466.0	452.0	414.0	476.0	400.0	612.0	376.0	374.0	472.0
% of System Peak	10.1	20.3	18.8	17.0	19.3	15.8	23.3	13.1	11.2	12.3

High Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	1595.0	1595.0	1595.0	1595.0	1595.0	1595.0	1895.0	2195.0	2495.0	3095.0
Oil	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Gas	131.0	131.0	131.0	131.0	131.0	131.0	131.0	131.0	131.0	131.0
Multi-fuelled										
Other	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
Other Fossil Fuelled										
Comb. Turbines	157.0	157.0	242.0	242.0	327.0	327.0	327.0	412.0	512.0	612.0
Int. Combustion										
Nuclear										
Hydro/Pumped Storage	589.0	841.0	841.0	841.0	841.0	841.0	841.0	841.0	841.0	841.0
Total Generating Capacity	2515.0	2767.0	2852.0	2852.0	2937.0	2937.0	3237.0	3622.0	4022.0	4722.0
Purchases[a]										
Capacity Available	2515.0	2767.0	2852.0	2852.0	2937.0	2937.0	3237.0	3622.0	4022.0	4722.0
Sales (Export)	7.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Domestic Peak Demand	2278.0	2301.0	2410.0	2454.0	2507.0	2610.0	2712.0	3041.0	3555.0	4016.0
System Peak	2285.0	2301.0	2410.0	2454.0	2507.0	2610.0	2712.0	3041.0	3555.0	4016.0
Remaining Capacity	230.0	466.0	442.0	398.0	430.0	327.0	525.0	581.0	467.0	706.0
% of System Peak	10.1	20.3	18.3	16.2	17.2	12.5	19.4	19.1	13.1	17.6

Note: [a] Includes imports and net capacity sales between provinces and capacity attributed to interconnected system.

Table A4-4 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts)

Alberta
Low Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	4462.0	4845.0	4845.0	4845.0	5251.0	5251.0	5634.0	6009.0	6322.0	7237.0
Oil	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Gas	1385.0	1385.0	1395.0	1395.0	1245.0	1245.0	1160.0	1190.0	950.0	960.0
Multi-fuelled										
Other	47.0	113.0	113.0	113.0	113.0	130.0	130.0	230.0	300.0	300.0
Other Fossil Fuelled										
Comb. Turbines	516.0	459.0	459.0	459.0	464.0	464.0	447.0	647.0	554.0	773.0
Int. Combustion	52.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0
Nuclear										
Hydro/Pumped Storage	734.0	734.0	734.0	734.0	734.0	734.0	734.0	734.0	734.0	734.0
Total Generating Capacity	7202.0	7597.0	7607.0	7607.0	7868.0	7885.0	8166.0	8871.0	8921.0	10065.0
Purchases[a]		300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
Capacity Available	7202.0	7897.0	7907.0	7907.0	8168.0	8185.0	8466.0	9171.0	9221.0	10365.0
Sales (Export)										
Domestic Peak Demand	5475.0	5782.0	5831.0	5809.0	5827.0	5876.0	5970.0	7006.0	7726.0	8505.0
System Peak	5475.0	5782.0	5831.0	5809.0	5827.0	5876.0	5970.0	7006.0	7726.0	8505.0
Remaining Capacity	1727.0	2115.0	2076.0	2098.0	2341.0	2309.0	2496.0	2165.0	1495.0	1860.0
% of System Peak	31.5	36.6	35.6	36.1	40.2	39.3	41.8	30.9	19.4	21.9

High Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	4462.0	4845.0	4845.0	4845.0	5251.0	5251.0	5634.0	6759.0	7822.0	8737.0
Oil	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Gas	1385.0	1385.0	1395.0	1395.0	1245.0	1245.0	1160.0	1190.0	950.0	960.0
Multi-fuelled										
Other	47.0	113.0	113.0	113.0	113.0	130.0	130.0	230.0	300.0	300.0
Other Fossil Fuelled										
Comb. Turbines	516.0	459.0	459.0	459.0	464.0	464.0	447.0	647.0	854.0	1173.0
Int. Combustion	52.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0
Nuclear										
Hydro/Pumped Storage	734.0	734.0	734.0	734.0	734.0	734.0	734.0	734.0	734.0	734.0
Total Generating Capacity	7202.0	7597.0	7607.0	7607.0	7868.0	7885.0	8166.0	9621.0	10721.0	11965.0
Purchases[a]	0.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
Capacity Available	7202.0	7897.0	7907.0	7907.0	8168.0	8185.0	8466.0	9921.0	11021.0	12265.0
Sales (Export)										
Domestic Peak Demand	5475.0	5782.0	5971.0	6087.0	6215.0	6382.0	6593.0	8125.0	9110.0	10058.0
System Peak	5475.0	5782.0	5971.0	6087.0	6215.0	6382.0	6593.0	8125.0	9110.0	10058.0
Remaining Capacity	1727.0	2115.0	1936.0	1820.0	1953.0	1803.0	1873.0	1796.0	1911.0	2207.0
% of System Peak	31.5	36.6	32.4	29.9	31.4	28.3	28.4	22.1	21.0	21.9

Note: [a] Includes imports and net capacity sales between provinces and capacity attributed to interconnected system.

Table A4-4 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts)

Prairies
Low Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	6426.0	6809.0	6809.0	6809.0	7215.0	7215.0	7898.0	8273.0	8886.0	10665.0
Oil	28.0	28.0	28.0	28.0	28.0	28.0	23.0	23.0	23.0	23.0
Gas	1570.0	1570.0	1580.0	1580.0	1430.0	1430.0	1350.0	1380.0	1140.0	1150.0
Multi-fuelled	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	91.0	157.0	157.0	157.0	157.0	174.0	174.0	274.0	344.0	344.0
Other Fossil Fuelled										
Comb. Turbines	691.0	634.0	719.0	719.0	809.0	809.0	792.0	992.0	1084.0	1328.0
Int. Combustion	82.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	4871.0	5123.0	5123.0	5123.0	5123.0	5251.0	5635.0	6793.0	7703.0	8053.0
Total Generating Capacity	13759.0	14406.0	14501.0	14501.0	14847.0	14992.0	15957.0	17820.0	19265.0	21648.0
Purchases[a]	300.0	600.0	600.0	600.0	600.0	600.0	600.0	500.0	600.0	600.0
Capacity Available	14059.0	15006.0	15101.0	15101.0	15447.0	15592.0	16557.0	18320.0	19865.0	22248.0
Sales (Export)	7.0	0.0	0.0	0.0	0.0	0.0	0.0	500.0	1050.0	1050.0
Domestic Peak Demand	10582.0	11135.0	11472.0	11749.0	11931.0	12134.0	12371.0	14285.0	16065.0	18059.0
System Peak	10589.0	11135.0	11472.0	11749.0	11931.0	12134.0	12371.0	14785.0	17115.0	19109.0
Remaining Capacity	3470.0	3871.0	3629.0	3352.0	3516.0	3458.0	4186.0	3535.0	2750.0	3139.0
% of System Peak	32.8	34.8	31.6	28.5	29.5	28.5	33.8	23.9	16.1	16.4

High Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	6426.0	6809.0	6809.0	6809.0	7215.0	7215.0	7898.0	9323.0	10686.0	12267.0
Oil	28.0	28.0	28.0	28.0	28.0	28.0	23.0	23.0	23.0	23.0
Gas	1570.0	1570.0	1580.0	1580.0	1430.0	1430.0	1350.0	1380.0	1140.0	1150.0
Multi-fuelled	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	91.0	157.0	157.0	157.0	157.0	174.0	174.0	274.0	344.0	344.0
Other Fossil Fuelled										
Comb. Turbines	691.0	634.0	719.0	719.0	809.0	809.0	792.0	1077.0	1384.0	1828.0
Int. Combustion	82.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0	85.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	4871.0	5123.0	5123.0	5123.0	5123.0	5251.0	5635.0	6793.0	7703.0	8053.0
Total Generating Capacity	13759.0	14406.0	14501.0	14501.0	14847.0	14992.0	15957.0	18955.0	21365.0	23750.0
Purchases[a]	300.0	600.0	600.0	600.0	600.0	600.0	600.0	500.0	600.0	600.0
Capacity Available	14059.0	15006.0	15101.0	15101.0	15447.0	15592.0	16557.0	19455.0	21965.0	24350.0
Sales (Export)	7.0	0.0	0.0	0.0	0.0	0.0	0.0	500.0	1050.0	1050.0
Domestic Peak Demand	10582.0	11135.0	11618.0	12015.0	12326.0	12676.0	13042.0	15529.0	17549.0	19582.0
System Peak	10589.0	11135.0	11618.0	12015.0	12326.0	12676.0	13042.0	16029.0	18599.0	20632.0
Remaining Capacity	3470.0	3871.0	3483.0	3086.0	3121.0	2916.0	3515.0	3426.0	3366.0	3718.0
% of System Peak	32.8	34.8	30.0	25.7	25.3	23.0	27.0	21.4	18.1	18.0

Note: [a] Includes imports and net capacity sales between provinces and capacity attributed to interconnected system.

Table A4-4 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

British Columbia
Low Price Case

(Megawatts)

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal										
Oil	138.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Gas	1040.0	1026.0	1026.0	1026.0	1030.0	1030.0	1030.0	1035.0	1035.0	1035.0
Multi-fuelled										
Other	224.0	224.0	224.0	224.0	230.0	230.0	230.0	250.0	250.0	250.0
Other Fossil Fuelled										
Comb. Turbines	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0
Int. Combustion	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0
Nuclear										
Hydro/Pumped Storage	11147.0	11218.0	11218.0	11218.0	11218.0	11218.0	11218.0	12208.0	13586.0	14886.0
Total Generating Capacity	12800.0	12844.0	12844.0	12844.0	12854.0	12854.0	12854.0	13869.0	15247.0	16547.0
Purchases[a]										
Capacity Available	12800.0	12844.0	12844.0	12844.0	12854.0	12854.0	12854.0	13869.0	15247.0	16547.0
Sales (Export)	7.0	7.0	7.0	7.0	7.0	7.0	7.0	832.0	832.0	832.0
Domestic Peak Demand	8250.0	8611.0	9216.0	9310.0	9495.0	9664.0	9788.0	10334.0	11603.0	13101.0
System Peak	8257.0	8618.0	9223.0	9317.0	9502.0	9671.0	9795.0	11166.0	12435.0	13933.0
Remaining Capacity	4543.0	4226.0	3621.0	3527.0	3352.0	3183.0	3059.0	2703.0	2812.0	2614.0
% of System Peak	55.0	49.0	39.3	37.9	35.3	32.9	31.2	24.2	22.6	18.8

High Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal										
Oil	138.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Gas	1040.0	1026.0	1026.0	1026.0	1030.0	1030.0	1030.0	1035.0	1035.0	1035.0
Multi-fuelled										
Other	224.0	224.0	224.0	224.0	230.0	230.0	230.0	250.0	250.0	250.0
Other Fossil Fuelled										
Comb. Turbines	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0
Int. Combustion	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0	79.0
Nuclear										
Hydro/Pumped Storage	11147.0	11218.0	11218.0	11218.0	11218.0	11218.0	11218.0	12208.0	12328.0	13586.0
Total Generating Capacity	12800.0	12844.0	12844.0	12844.0	12854.0	12854.0	12854.0	13869.0	13989.0	15247.0
Purchases[a]										
Capacity Available	12800.0	12844.0	12844.0	12844.0	12854.0	12854.0	12854.0	13869.0	13989.0	15247.0
Sales (Export)	7.0	7.0	7.0	7.0	7.0	7.0	7.0	832.0	832.0	832.0
Domestic Peak Demand	8250.0	8611.0	9163.0	9159.0	9270.0	9371.0	9416.0	9780.0	10740.0	11730.0
System Peak	8257.0	8618.0	9170.0	9166.0	9277.0	9378.0	9423.0	10612.0	11572.0	12562.0
Remaining Capacity	4543.0	4226.0	3674.0	3678.0	3577.0	3476.0	3431.0	3257.0	2417.0	2685.0
% of System Peak	55.0	49.0	40.1	40.1	38.6	37.1	36.4	30.7	20.9	21.4

Note: [a] Includes imports and net capacity sales between provinces and capacity attributed to interconnected system.

Table A4-4 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts)

Yukon
Low Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal										
Oil										
Gas										
Multi-fuelled										
Other										
Other Fossil Fuelled										
Comb. Turbines										
Int. Combustion	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
Nuclear										
Hydro/Pumped Storage	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Total Generating Capacity	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0
Purchases[a]										
Capacity Available	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0
Sales (Export)										
Domestic Peak Demand	53.0	45.0	45.0	45.0	46.0	46.0	46.0	47.0	48.0	49.0
System Peak	53.0	45.0	45.0	45.0	46.0	46.0	46.0	47.0	48.0	49.0
Remaining Capacity	69.0	77.0	77.0	77.0	76.0	76.0	76.0	75.0	74.0	73.0
% of System Peak	130.2	171.1	171.1	171.1	165.2	165.2	165.2	159.6	154.2	149.0
High Price Case										
Fossil Fuelled Steam										
Coal										
Oil										
Gas										
Multi-fuelled										
Other										
Other Fossil Fuelled										
Comb. Turbines	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0	42.0
Int. Combustion										
Nuclear										
Hydro/Pumped Storage	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0
Total Generating Capacity	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0
Purchases[a]										
Capacity Available	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0	122.0
Sales (Export)										
Domestic Peak Demand	53.0	42.0	43.0	43.0	44.0	45.0	46.0	51.0	56.0	62.0
System Peak	53.0	42.0	43.0	43.0	44.0	45.0	46.0	51.0	56.0	62.0
Remaining Capacity	69.0	80.0	79.0	79.0	78.0	77.0	76.0	71.0	66.0	60.0
% of System Peak	130.2	190.5	183.7	183.7	177.3	171.1	165.2	139.2	117.9	96.8

Note: [a] Includes imports and net capacity sales between provinces and capacity attributed to interconnected system.

Table A4-4 (Continued)
Generating Capacity by Fuel Type - Canada, Provinces and Territories

(Megawatts)

Northwest Territories
Low Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal										
Oil										
Gas										
Multi-fuelled										
Other										
Other Fossil Fuelled										
Comb. Turbines										
Int. Combustion	148.0	148.0	148.0	148.0	148.0	148.0	148.0	148.0	155.0	176.0
Nuclear										
Hydro/Pumped Storage	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	53.0
Total Generating Capacity	191.0	191.0	191.0	191.0	191.0	191.0	191.0	191.0	198.0	229.0
Purchases[a]										
Capacity Available	191.0	191.0	191.0	191.0	191.0	191.0	191.0	191.0	198.0	229.0
Sales (Export)										
Domestic Peak Demand	191.0	128.0	124.0	122.0	129.0	133.0	134.0	149.0	167.0	190.0
System Peak	191.0	128.0	124.0	122.0	129.0	133.0	134.0	149.0	167.0	190.0
Remaining Capacity	0.0	63.0	67.0	69.0	62.0	58.0	57.0	42.0	31.0	39.0
% of System Peak	0.0	49.2	54.0	56.6	48.1	43.6	42.5	28.2	18.6	20.5

High Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal										
Oil										
Gas										
Multi-fuelled										
Other										
Other Fossil Fuelled										
Comb. Turbines										
Int. Combustion	148.0	148.0	148.0	148.0	148.0	148.0	148.0	148.0	148.0	176.0
Nuclear										
Hydro/Pumped Storage	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0	43.0
Total Generating Capacity	191.0	191.0	191.0	191.0	191.0	191.0	191.0	191.0	191.0	219.0
Purchases[a]										
Capacity Available	191.0	191.0	191.0	191.0	191.0	191.0	191.0	191.0	191.0	219.0
Sales (Export)										
Domestic Peak Demand	193.0	124.0	122.0	123.0	126.0	128.0	131.0	146.0	163.0	183.0
System Peak	193.0	124.0	122.0	123.0	126.0	128.0	131.0	146.0	163.0	183.0
Remaining Capacity	-2.0	67.0	69.0	68.0	65.0	63.0	60.0	45.0	28.0	36.0
% of System Peak	-1.0	54.0	56.6	55.3	51.6	49.2	45.8	30.8	17.2	19.7

Note: [a] Includes imports and net capacity sales between provinces and capacity attributed to interconnected system.

(Megawatts)

British Columbia, Yukon and Northwest Territories

Low Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	138.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Gas	1040.0	1026.0	1026.0	1026.0	1030.0	1030.0	1030.0	1035.0	1035.0	1035.0
Multi-fuelled	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	224.0	224.0	224.0	224.0	230.0	230.0	230.0	250.0	250.0	250.0
Other Fossil Fuelled										
Comb. Turbines	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0	172.0
Int. Combustion	269.0	269.0	269.0	269.0	269.0	269.0	269.0	269.0	276.0	297.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	11270.0	11341.0	11341.0	11341.0	11341.0	11341.0	11341.0	12331.0	13709.0	15019.0
Total Generating Capacity	13113.0	13157.0	13157.0	13157.0	13167.0	13167.0	13167.0	14182.0	15567.0	16898.0
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Available	13113.0	13157.0	13157.0	13157.0	13167.0	13167.0	13167.0	14182.0	15567.0	16898.0
Sales (Export)	7.0	7.0	7.0	7.0	7.0	7.0	7.0	832.0	832.0	832.0
Domestic Peak Demand	8494.0	8784.0	9385.0	9477.0	9670.0	9843.0	9968.0	10530.0	11818.0	13340.0
System Peak	8501.0	8791.0	9392.0	9484.0	9677.0	9850.0	9975.0	11362.0	12650.0	14172.0
Remaining Capacity	4612.0	4366.0	3765.0	3673.0	3490.0	3317.0	3192.0	2820.0	2917.0	2726.0
% of System Peak	54.3	49.7	40.1	38.7	36.1	33.7	32.0	24.8	23.1	19.2

High Price Case

Type of Capacity	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Fossil Fuelled Steam										
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	138.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0
Gas	1040.0	1026.0	1026.0	1026.0	1030.0	1030.0	1030.0	1035.0	1035.0	1035.0
Multi-fuelled	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	224.0	224.0	224.0	224.0	230.0	230.0	230.0	250.0	250.0	250.0
Other Fossil Fuelled										
Comb. Turbines	214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0
Int. Combustion	227.0	227.0	227.0	227.0	227.0	227.0	227.0	227.0	227.0	255.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro/Pumped Storage	11270.0	11341.0	11341.0	11341.0	11341.0	11341.0	11341.0	12331.0	12451.0	13709.0
Total Generating Capacity	13113.0	13157.0	13157.0	13157.0	13167.0	13167.0	13167.0	14182.0	14302.0	15588.0
Purchases[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Capacity Available	13113.0	13157.0	13157.0	13157.0	13167.0	13167.0	13167.0	14182.0	14302.0	15588.0
Sales (Export)	7.0	7.0	7.0	7.0	7.0	7.0	7.0	832.0	832.0	832.0
Domestic Peak Demand	8496.0	8777.0	9328.0	9325.0	9440.0	9544.0	9593.0	9977.0	10959.0	11975.0
System Peak	8503.0	8784.0	9335.0	9332.0	9447.0	9551.0	9600.0	10809.0	11791.0	12807.0
Remaining Capacity	4610.0	4373.0	3822.0	3825.0	3720.0	3616.0	3567.0	3373.0	2511.0	2781.0
% of System Peak	54.2	49.8	40.9	41.0	39.4	37.9	37.2	31.2	21.3	21.7

Note [a] Includes imports and net capacity sales between provinces and capacity attributed to interconnected system.

Table A4-5
Energy Generation by Fuel Type - Canada, Provinces and Territories

Canada

Low Price Case

(Terawatt hours) Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous	11.0	13.1	10.5	10.7	10.7	10.7	13.7	21.5	27.0	32.6
-Sub-Bituminous	57.1	49.1	51.0	48.7	42.1	43.2	42.3	50.6	75.6	91.9
-Lignite	10.7	10.8	9.0	9.3	9.5	10.0	10.1	11.6	13.9	17.1
Oil Fired Steam										
-Light	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	5.3	6.1	6.5	6.7	7.5	8.2	5.9	4.2	4.1	8.3
Natural Gas Fired Steam	3.0	4.0	3.0	3.3	3.4	3.2	3.5	4.5	4.9	5.7
Comb. Turbines										
-Light Oil	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.9
-Natural Gas	2.5	2.5	2.1	2.1	2.2	2.3	2.3	2.5	2.7	3.0
Internal Combustion										
-Diesel Oil	0.7	0.6	1.0	1.0	1.0	1.1	1.1	1.2	1.3	1.4
Nuclear	49.2	57.1	64.6	74.1	87.2	93.3	99.5	111.9	111.7	124.8
Hydroelectric	283.3	300.7	313.1	323.1	326.0	321.7	328.0	355.9	392.5	428.1
Other	2.2	2.3	2.4	2.5	2.6	2.8	2.9	3.9	4.5	4.7
Total Energy Generation	425.4	446.4	463.3	481.5	492.2	496.5	509.4	567.9	638.4	718.6
Tot. Domestic Consumption	386.3	405.8	423.8	434.5	446.4	448.1	456.5	515.6	582.4	668.6
Exports (Net)	39.1	40.7	39.5	47.0	45.7	48.4	53.0	52.3	56.0	50.1

High Price Case

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous	11.0	13.1	10.3	10.5	10.5	10.6	13.5	21.1	24.5	28.9
-Sub-Bituminous	57.1	49.1	51.4	48.1	41.9	41.3	41.8	54.3	78.7	92.3
-Lignite	10.7	10.8	9.0	9.4	9.7	10.2	10.5	12.5	15.1	17.7
Oil Fired Steam										
-Light	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	5.3	6.1	6.6	7.1	7.7	8.6	6.6	3.4	3.8	4.4
Natural Gas Fired Steam	3.0	4.0	3.2	3.7	4.0	3.5	3.9	4.9	5.6	5.3
Comb. Turbines										
-Light Oil	0.2	0.2	0.0	0.0	0.0	0.0	0.2	0.1	0.2	0.6
-Natural Gas	2.5	2.5	2.1	2.2	2.2	2.3	2.4	2.7	2.7	2.9
Internal Combustion										
-Diesel Oil	0.7	0.6	1.0	1.0	1.0	1.0	1.1	1.2	1.2	1.4
Nuclear	49.2	57.1	64.9	74.3	87.4	93.6	99.8	112.1	112.0	131.6
Hydroelectric	283.3	300.7	315.9	323.8	326.9	322.1	328.6	356.3	383.4	417.9
Other	2.2	2.3	2.4	2.5	2.6	2.8	2.9	3.9	4.5	4.7
Total Energy Generation	425.4	446.4	466.8	482.5	493.9	496.0	511.3	572.5	631.7	707.7
Tot. Domestic Consumption	386.3	405.8	423.8	432.3	442.3	443.2	451.5	509.5	574.3	652.8
Exports (Net)	39.1	40.7	43.6	50.2	51.7	52.9	59.8	63.0	57.4	54.9

(Gigawatt hours)

Newfoundland
Low Price Case

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous										
-Sub-Bituminous										
-Lignite										
Oil Fired Steam										
-Light										
-Heavy	781.0	1746.0	697.0	793.0	833.0	913.0	1305.0	770.0	142.0	186.0
Natural Gas Fired Steam										
Comb. Turbines										
-Light Oil	1.0	0.0	36.0	40.0	42.0	45.0	70.0	59.0	2.0	2.0
-Natural Gas										
Internal Combustion										
-Diesel Oil	92.0	1.0	35.0	37.0	37.0	38.0	45.0	30.0	25.0	25.0
Nuclear										
Hydroelectric	44775.0	39640.0	45189.0	45270.0	45290.0	45348.0	45501.0	47343.0	56715.0	56743.0
Other								10.0	35.0	80.0
Total Energy Generation	45649.0	41387.0	45957.0	46140.0	46202.0	46344.0	46921.0	48212.0	56919.0	57036.0
Tot. Domestic Consumption	9636.0	8857.0	10116.0	10303.0	10370.0	10516.0	11098.0	11811.0	12840.0	15480.0
Interprovincial Transfers (net)	36013.0	32505.0	35841.0	35837.0	35832.0	35828.0	35823.0	36452.0	44058.0	41556.0
Exports (Net)										

High Price Case

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous										
-Sub-Bituminous										
-Lignite										
Oil Fired Steam										
-Light										
-Heavy	781.0	1746.0	672.0	834.0	1223.0	1636.0	2436.0	320.0	228.0	651.0
Natural Gas Fired Steam										
Comb. Turbines										
-Light Oil	1.0	0.0	36.0	42.0	57.0	78.0	211.0	9.0	2.0	86.0
-Natural Gas										
Internal Combustion										
-Diesel Oil	92.0	1.0	36.0	38.0	42.0	47.0	59.0	25.0	25.0	28.0
Nuclear										
Hydroelectric	44775.0	39640.0	45306.0	45426.0	45488.0	45488.0	45488.0	51096.0	56749.0	56761.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	35.0	80.0
Total Energy Generation	45649.0	41387.0	46050.0	46340.0	46810.0	47249.0	48194.0	51460.0	57039.0	57606.0
Tot. Domestic Consumption	9636.0	8857.0	10209.0	10503.0	10978.0	11421.0	12371.0	13159.0	16460.0	19650.0
Interprovincial Transfers (net)	36013.0	32505.0	35791.0	35787.0	35782.0	35778.0	35823.0	38251.0	40529.0	37906.0
Exports (Net)										

Table A4-5 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

(Gigawatt hours)										
					Nova Scotia Low Price Case					
Type of Generation	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Coal Fired Steam										
-Bituminous	4878.0	5440.0	5490.0	5521.0	5525.0	5580.0	6185.0	6699.0	8586.0	10546.0
-Sub-Bituminous										
-Lignite										
Oil Fired Steam										
-Light	12.0	12.0								
-Heavy	1303.0	1031.0	1077.0	1144.0	1158.0	1299.0	762.0	1645.0	1625.0	1764.0
Natural Gas Fired Steam										
Comb. Turbines										
-Light Oil		2.0				1.0	2.0	112.0	173.0	329.0
-Natural Gas										
Internal Combustion										
-Diesel Oil										
Nuclear										
Hydroelectric	1034.0	908.0	1072.0	1072.0	1072.0	1072.0	1072.0	1072.0	1072.0	1072.0
Other	8.0	117.0	101.0	103.0	105.0	107.0	109.0	125.0	135.0	128.0
Total Energy Generation	7235.0	7510.0	7740.0	7840.0	7860.0	8059.0	8130.0	9653.0	11591.0	13839.0
Tot. Domestic Consumption	7266.0	7640.0	7940.0	8040.0	8060.0	8259.0	8330.0	9853.0	11791.0	14039.0
Interprovincial Transfers (net)	-31.0	-130.0	-200.0	-200.0	-200.0	-200.0	-200.0	-200.0	-200.0	-200.0
Exports (Net)										
					High Price Case					
Coal Fired Steam										
-Bituminous	4878.0	5440.0	5484.0	5498.0	5484.0	5547.0	6076.0	6668.0	7764.0	9684.0
-Sub-Bituminous										
-Lignite										
Oil Fired Steam										
-Light	12.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	1303.0	1031.0	1063.0	1097.0	1069.0	1164.0	653.0	1485.0	1836.0	1798.0
Natural Gas Fired Steam										
Comb. Turbines										
-Light Oil	0.0	2.0	0.0	0.0	0.0	0.0	0.0	79.0	166.0	256.0
-Natural Gas										
Internal Combustion										
-Diesel Oil										
Nuclear										
Hydroelectric	1034.0	908.0	1072.0	1072.0	1072.0	1072.0	1072.0	1072.0	1072.0	1072.0
Other	8.0	117.0	101.0	103.0	105.0	107.0	109.0	125.0	135.0	128.0
Total Energy Generation	7235.0	7510.0	7720.0	7770.0	7730.0	7890.0	7910.0	9429.0	10973.0	12938.0
Tot. Domestic Consumption	7266.0	7640.0	7920.0	7970.0	7930.0	8090.0	8110.0	9629.0	11173.0	13138.0
Interprovincial Transfers (net)	-31.0	-130.0	-200.0	-200.0	-200.0	-200.0	-200.0	-200.0	-200.0	-200.0
Exports (Net)										

(Gigawatt hours)	Prince Edward Island Low Price Case									
Type of Generation	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Coal Fired Steam										
-Bituminous										
-Sub-Bituminous										
-Lignite										
Oil Fired Steam										
-Light										
-Heavy	1.0	1.0	5.0	4.0	4.0	4.0	5.0	5.0	5.0	5.0
Natural Gas Fired Steam										
Comb. Turbines										
-Light Oil										
-Natural Gas										
Internal Combustion										
-Diesel Oil	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear										
Hydroelectric										
Other										
Total Energy Generation	2.0	2.0	5.0	4.0	4.0	4.0	5.0	5.0	5.0	5.0
Tot. Domestic Consumption	552.0	576.0	600.0	619.0	629.0	639.0	660.0	730.0	800.0	880.0
Interprovincial Transfers (net)	-550.0	-574.0	-595.0	-615.0	-625.0	-635.0	-655.0	-725.0	-795.0	-875.0
Exports (Net)										
	High Price Case									
Coal Fired Steam										
-Bituminous										
-Sub-Bituminous										
-Lignite										
Oil Fired Steam										
-Light										
-Heavy	1.0	1.0	5.0	4.0	4.0	4.0	4.0	3.0	2.0	1.0
Natural Gas Fired Steam										
Comb. Turbines										
-Light Oil										
-Natural Gas										
Internal Combustion										
-Diesel Oil	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear										
Hydroelectric										
Other										
Total Energy Generation	2.0	2.0	5.0	4.0	4.0	4.0	4.0	3.0	2.0	1.0
Tot. Domestic Consumption	552.0	576.0	600.0	609.0	629.0	639.0	660.0	740.0	820.0	890.0
Interprovincial Transfers (net)	-550.0	-574.0	-595.0	-605.0	-625.0	-635.0	-656.0	-737.0	-818.0	-889.0
Exports (Net)										

Table A4-5 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

(Gigawatt hours)					New Brunswick Low Price Case					
Type of Generation	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Coal Fired Steam										
-Bituminous	1594.0	1021.0	2142.0	2296.0	2296.0	2296.0	4644.0	11909.0	15466.0	19172.0
-Sub-Bituminous										
-Lignite										
Oil Fired Steam										
-Light	17.0	12.0								
-Heavy	2367.0	2435.0	3820.0	3770.0	4521.0	4957.0	2774.0	781.0	682.0	717.0
Natural Gas Fired Steam										
Comb. Turbines										
-Light Oil						1.0	1.0	68.0	58.0	87.0
-Natural Gas										
Internal Combustion										
-Diesel Oil										
Nuclear	5007.0	5428.0	4503.0	4503.0	4503.0	4503.0	4503.0	4503.0	4503.0	4503.0
Hydroelectric	3121.0	2258.0	2806.0	2806.0	2806.0	2806.0	2806.0	2806.0	2806.0	2806.0
Other	289.0	268.0	297.0	349.0	351.0	353.0	354.0	361.0	365.0	365.0
Total Energy Generation	12395.0	11422.0	13568.0	13724.0	14477.0	14916.0	15082.0	20428.0	23880.0	27650.0
Tot. Domestic Consumption	10515.0	9839.0	11480.0	11616.0	12359.0	12788.0	12934.0	15458.0	18440.0	22030.0
Interprovincial Transfers (net)	-3759.0	-4668.0	-5205.0	-5185.0	-5175.0	-5165.0	-5145.0	-2075.0	-3005.0	-2925.0
Exports (Net)	5639.0	6215.0	7293.0	7293.0	7293.0	7293.0	7293.0	7043.0	8443.0	8545.0
					High Price Case					
Coal Fired Steam										
-Bituminous	1594.0	1021.0	1995.0	2151.0	2151.0	2151.0	4527.0	11505.0	13791.0	16284.0
-Sub-Bituminous										
-Lignite										
Oil Fired Steam										
-Light	17.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	2367.0	2435.0	3948.0	4186.0	4438.0	4767.0	2468.0	646.0	671.0	898.0
Natural Gas Fired Steam										
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.0	74.0	254.0
-Natural Gas										
Internal Combustion										
-Diesel Oil										
Nuclear	5007.0	5428.0	4745.0	4745.0	4745.0	4745.0	4745.0	4745.0	4745.0	4745.0
Hydroelectric	3121.0	2258.0	2879.0	2879.0	2879.0	2879.0	2879.0	2879.0	2879.0	2879.0
Other	289.0	268.0	297.0	349.0	351.0	353.0	354.0	361.0	365.0	365.0
Total Energy Generation	12395.0	11422.0	13864.0	14310.0	14564.0	14895.0	14973.0	20188.0	22525.0	25425.0
Tot. Domestic Consumption	10515.0	9839.0	11444.0	11880.0	12114.0	12435.0	12492.0	15053.0	17109.0	20138.0
Interprovincial Transfers (net)	-3759.0	-4668.0	-5800.0	5195.0	-5175.0	-5165.0	-5144.0	-3063.0	-2982.0	-2911.0
Exports (Net)	5639.0	6215.0	8220.0	7625.0	7625.0	7625.0	7625.0	8198.0	8398.0	8198.0

(Gigawatt hours)

Atlantic
Low Price Case

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous	6472.0	6461.0	7632.0	7817.0	7821.0	7876.0	10829.0	18608.0	24052.0	29718.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	29.0	24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	4452.0	5213.0	5599.0	5711.0	6516.0	7173.0	4846.0	3201.0	2454.0	2672.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	1.0	2.0	36.0	40.0	42.0	47.0	73.0	239.0	233.0	418.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	93.0	2.0	35.0	37.0	37.0	38.0	45.0	30.0	25.0	25.0
Nuclear	5007.0	5428.0	4503.0	4503.0	4503.0	4503.0	4503.0	4503.0	4503.0	4503.0
Hydroelectric	48930.0	42806.0	49067.0	49148.0	49168.0	49226.0	49379.0	51221.0	60593.0	60621.0
Other	297.0	385.0	398.0	452.0	456.0	460.0	463.0	496.0	535.0	573.0
Total Energy Generation	65281.0	60321.0	67270.0	67708.0	68543.0	69323.0	70138.0	78298.0	92395.0	98530.0
Tot. Domestic Consumption	27969.0	26912.0	30136.0	30578.0	31418.0	32202.0	33022.0	37852.0	43871.0	52429.0
Exports (Net)	5639.0	6215.0	7293.0	7293.0	7293.0	7293.0	7293.0	7043.0	8443.0	8545.0

High Price Case

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous	6472.0	6461.0	7479.0	7649.0	7635.0	7698.0	10603.0	18173.0	21555.0	25968.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	29.0	24.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	4452.0	5213.0	5688.0	6121.0	6734.0	7571.0	5561.0	2454.0	2737.0	3348.0
Natural Gas Fired Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Comb. Turbines										
-Light Oil	1.0	2.0	36.0	42.0	57.0	78.0	211.0	140.0	242.0	596.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	93.0	2.0	36.0	38.0	42.0	47.0	59.0	25.0	25.0	28.0
Nuclear	5007.0	5428.0	4745.0	4745.0	4745.0	4745.0	4745.0	4745.0	4745.0	4745.0
Hydroelectric	48930.0	42806.0	49257.0	49377.0	49439.0	49439.0	49439.0	55047.0	60700.0	60712.0
Other	297.0	385.0	398.0	452.0	456.0	460.0	463.0	496.0	535.0	573.0
Total Energy Generation	65281.0	60321.0	67639.0	68424.0	69108.0	70038.0	71081.0	81080.0	90539.0	95970.0
Tot. Domestic Consumption	27969.0	26912.0	30173.0	30962.0	31651.0	32585.0	33633.0	38581.0	45562.0	53816.0
Exports (Net)	5639.0	6215.0	8220.0	7625.0	7625.0	7625.0	7625.0	6875.0	8398.0	7875.0

Table A4-5 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Quebec
Low Price Case

(Gigawatt hours)

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous										
-Sub-Bituminous										
-Lignite										
Oil Fired Steam										
-Light										
-Heavy	29.0	19.0	30.0	30.0	30.0	60.0	60.0	50.0	239.0	1208.0
Natural Gas Fired Steam										
Comb. Turbines										
-Light Oil										
-Natural Gas										
Internal Combustion										
-Diesel Oil	192.0	199.0	192.0	192.0	225.0	225.0	225.0	282.0	300.0	336.0
Nuclear	3422.0	3209.0	4415.0	4415.0	4415.0	4415.0	4415.0	4415.0	4415.0	4415.0
Hydroelectric[a]	118535.0	133298.0	140572.0	150496.0	153328.0	148952.0	154137.0	166242.0	179907.0	206455.0
Other			20.0	20.0	20.0	40.0	40.0	50.0	50.0	50.0
Total Energy Generation	122178.0	136725.0	145229.0	155153.0	158018.0	153692.0	158877.0	171039.0	184911.0	212464.0
Tot. Domestic Consumption	135310.0	145797.0	151520.0	155440.0	159300.0	153970.0	157650.0	178790.0	201540.0	230370.0
Interprovincial Transfers (net)	-24374.0	-18625.0	-21341.0	-23837.0	-24832.0	-26828.0	-27832.0	-31452.0	-37058.0	-34556.0
Exports (Net)	11242.0	9603.0	15120.0	23550.0	23550.0	26550.0	29050.0	23650.0	20450.0	16650.0

High Price Case

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous										
-Sub-Bituminous										
-Lignite										
Oil Fired Steam										
-Light										
-Heavy	29.0	19.0	30.0	30.0	30.0	60.0	60.0	50.0	50.0	50.0
Natural Gas Fired Steam										
Comb. Turbines										
-Light Oil										
-Natural Gas										
Internal Combustion										
-Diesel Oil	192.0	199.0	192.0	192.0	225.0	225.0	225.0	282.0	300.0	336.0
Nuclear	3422.0	3209.0	4415.0	4415.0	4415.0	4415.0	4415.0	4415.0	4415.0	4415.0
Hydroelectric	118535.0	133298.0	143242.0	151026.0	154048.0	149192.0	154607.0	166292.0	177326.0	203083.0
Other	0.0	0.0	20.0	20.0	20.0	40.0	40.0	50.0	50.0	50.0
Total Energy Generation	122178.0	136725.0	147899.0	155683.0	158738.0	153932.0	159347.0	171089.0	182141.0	207934.0
Tot. Domestic Consumption	135310.0	145797.0	151190.0	153970.0	157020.0	151210.0	154620.0	174640.0	196070.0	221940.0
Interprovincial Transfers (net)	-24374.0	-18625.0	-21341.0	-23837.0	-23832.0	-23828.0	-26823.0	-32301.0	-33579.0	-30956.0
Exports (Net)	11242.0	9603.0	18050.0	25550.0	25550.0	26550.0	31550.0	28750.0	19650.0	16950.0

Note: [a] Hydro generation includes losses attributable to pumped storage hydro plants.

(Gigawatt hours)				Ontario						
				Low Price Case						
Type of Generation	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Coal Fired Steam										
-Bituminous	3920.0	5945.0	2840.0	2850.0	2860.0	2870.0	2880.0	2900.0	2900.0	2900.0
-Sub-Bituminous	31915.0	23134.0	23260.0	21052.0	14225.0	14619.0	12901.0	16606.0	38107.0	50645.0
-Lignite	1485.0	1196.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0
Oil Fired Steam										
-Light	128.0	101.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	162.0	171.0	150.0	240.0	240.0	306.0	306.0	306.0	847.0	3861.0
Natural Gas Fired Steam	413.0	439.0	500.0	722.0	788.0	788.0	788.0	876.0	963.0	963.0
Comb. Turbines										
-Light Oil	10.0	8.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	445.0
-Natural Gas	921.0	850.0	1050.0	1080.0	1110.0	1140.0	1170.0	1320.0	1470.0	1714.0
Internal Combustion										
-Diesel Oil	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	40818.0	48458.0	55715.0	65183.0	78253.0	84427.0	90601.0	102949.0	102795.0	115915.0
Hydroelectric	40698.0	41216.0	39904.0	39904.0	39904.0	39904.0	39904.0	43545.0	43645.0	43745.0
Other	134.0	142.0	142.0	142.0	142.0	142.0	202.0	302.0	302.0	402.0
Total Energy Generation	120605.0	121661.0	124567.0	132173.0	138522.0	145196.0	149752.0	169804.0	192029.0	221590.0
Tot. Domestic Consumption	118383.0	122224.0	127929.0	132899.0	138440.0	142599.0	144459.0	164339.0	185800.0	215710.0
Interprovincial Transfers (net)	-8235.0	-9427.0	-9507.0	-7107.0	-6107.0	-4107.0	-3107.0	-3207.0	-4307.0	-4307.0
Exports (Net)	10457.0	8864.0	6145.0	6381.0	6189.0	6704.0	8400.0	8672.0	10536.0	10187.0
				High Price Case						
Coal Fired Steam										
-Bituminous	3920.0	5945.0	2840.0	2850.0	2860.0	2870.0	2880.0	2900.0	2900.0	2900.0
-Sub-Bituminous	31915.0	23134.0	23050.0	19316.0	12455.0	10258.0	9524.0	14467.0	31729.0	40330.0
-Lignite	1485.0	1196.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0	1000.0
Oil Fired Steam										
-Light	128.0	101.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	162.0	171.0	150.0	240.0	240.0	306.0	306.0	306.0	438.0	438.0
Natural Gas Fired Steam	413.0	439.0	500.0	722.0	788.0	788.0	788.0	876.0	963.0	963.0
Comb. Turbines										
-Light Oil	10.0	8.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	921.0	850.0	1050.0	1080.0	1110.0	1140.0	1170.0	1320.0	1470.0	1500.0
Internal Combustion										
-Diesel Oil	1.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	40818.0	48458.0	55715.0	65183.0	78253.0	84427.0	90601.0	102949.0	102795.0	122475.0
Hydroelectric	40698.0	41216.0	39904.0	39904.0	39904.0	39904.0	39904.0	40004.0	43645.0	43745.0
Other	134.0	142.0	142.0	142.0	142.0	142.0	202.0	302.0	302.0	402.0
Total Energy Generation	120605.0	121661.0	124351.0	130437.0	136752.0	140835.0	146375.0	164124.0	185242.0	213753.0
Tot. Domestic Consumption	118383.0	122224.0	127709.0	131109.0	135380.0	138709.0	140179.0	157609.0	177620.0	205440.0
Interprovincial Transfers (net)	-8235.0	-9427.0	9507.0	-7107.0	-7107.0	-7107.0	-4107.0	-3207.0	-4307.0	-4307.0
Exports (Net)	10457.0	8864.0	6149.0	6435.0	8479.0	9233.0	10303.0	9722.0	11929.0	12620.0

Table A4-5 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Manitoba

Low Price Case

(Gigawatt hours) Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous										
-Sub-Bituminous										
-Lignite	148.0	266.0	56.0	196.0	233.0	356.0	133.0	265.0	144.0	607.0
Oil Fired Steam										
-Light										
-Heavy	20.0	20.0	25.0	25.0	25.0	25.0	15.0	15.0	15.0	15.0
Natural Gas Fired Steam	10.0	10.0	10.0	10.0	10.0	10.0	20.0	20.0	20.0	20.0
Comb. Turbines										
-Light Oil										
-Natural Gas										
Internal Combustion										
-Diesel Oil	53.0	55.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0
Nuclear										
Hydroelectric	21225.0	22361.0	21337.0	21337.0	21337.0	21337.0	22391.0	28213.0	34944.0	36881.0
Other	31.0	29.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Total Energy Generation	21487.0	22741.0	21516.0	21656.0	21693.0	21816.0	22647.0	28601.0	35211.0	37611.0
Tot. Domestic Consumption	15242.0	15744.0	16660.0	17400.0	17786.0	18159.0	18440.0	21590.0	24400.0	27900.0
Interprovincial Transfers (net)	1232.0	1282.0	1307.0	1407.0	1407.0	1407.0	1407.0	1507.0	1607.0	1607.0
Exports (Net)	5013.0	5715.0	3550.0	2850.0	2500.0	2250.0	2800.0	5504.0	9204.0	8104.0

High Price Case

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous										
-Sub-Bituminous										
-Lignite	148.0	266.0	36.0	156.0	247.0	287.0	143.0	185.0	134.0	387.0
Oil Fired Steam										
-Light										
-Heavy	20.0	20.0	25.0	25.0	25.0	25.0	15.0	15.0	15.0	15.0
Natural Gas Fired Steam	10.0	10.0	10.0	10.0	10.0	10.0	20.0	20.0	20.0	20.0
Comb. Turbines										
-Light Oil										
-Natural Gas										
Internal Combustion										
-Diesel Oil	53.0	55.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0	58.0
Nuclear										
Hydroelectric	21225.0	22361.0	21337.0	21337.0	21337.0	21337.0	22391.0	28213.0	34944.0	36881.0
Other	31.0	29.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
Total Energy Generation	21487.0	22741.0	21496.0	21616.0	21707.0	21747.0	22657.0	28521.0	35201.0	37391.0
Tot. Domestic Consumption	15242.0	15744.0	16640.0	17260.0	17600.0	17990.0	18250.0	21510.0	24090.0	27180.0
Interprovincial Transfers (net)	1232.0	1282.0	1307.0	1107.0	1407.0	1407.0	1407.0	1507.0	1607.0	1607.0
Exports (Net)	5013.0	5715.0	3550.0	2950.0	2700.0	2350.0	3000.0	5504.0	9504.0	8604.0

Saskatchewan
Low Price Case

(Gigawatt hours)

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous										
-Sub-Bituminous	26.0	28.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
-Lignite	9074.0	9309.0	7961.0	8143.0	8249.0	8598.0	8980.0	10320.0	12768.0	15539.0
Oil Fired Steam										
-Light	14.0	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	42.0	39.0	40.0	40.0	40.0	40.0	20.0	20.0	20.0	20.0
Natural Gas Fired Steam	486.0	290.0	250.0	257.0	261.0	278.0	321.0	318.0	345.0	304.0
Comb. Turbines										
-Light Oil										
-Natural Gas	37.0	45.0	46.0	69.0	76.0	114.0	160.0	102.0	186.0	97.0
Internal Combustion										
-Diesel Oil	6.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear										
Hydroelectric	1704.0	1941.0	3765.0	3765.0	3765.0	3775.0	3775.0	3795.0	3805.0	3815.0
Other	153.0	143.0	150.0	150.0	150.0	150.0	170.0	180.0	200.0	250.0
Total Energy Generation	11542.0	11815.0	12277.0	12489.0	12606.0	13020.0	13491.0	14800.0	17389.0	20090.0
Tot. Domestic Consumption	11814.0	12205.0	12477.0	12689.0	12806.0	13220.0	13691.0	15000.0	17589.0	20290.0
Interprovincial Transfers (net)	-292.0	-460.0	-300.0	-300.0	-300.0	-300.0	-300.0	-300.0	-300.0	-300.0
Exports (Net)	20.0	70.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

High Price Case

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous										
-Sub-Bituminous	26.0	28.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
-Lignite	9074.0	9309.0	8005.0	8214.0	8458.0	8915.0	9341.0	11357.0	13965.0	16293.0
Oil Fired Steam										
-Light	14.0	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	42.0	39.0	40.0	40.0	40.0	40.0	20.0	20.0	20.0	20.0
Natural Gas Fired Steam	486.0	290.0	251.0	260.0	271.0	297.0	347.0	289.0	313.0	332.0
Comb. Turbines										
-Light Oil										
-Natural Gas	37.0	45.0	47.0	74.0	91.0	152.0	215.0	44.0	112.0	185.0
Internal Combustion										
-Diesel Oil	6.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear										
Hydroelectric	1704.0	1941.0	3765.0	3765.0	3765.0	3775.0	3775.0	3795.0	3805.0	3815.0
Other	153.0	143.0	150.0	150.0	150.0	150.0	170.0	180.0	200.0	250.0
Total Energy Generation	11542.0	11815.0	12323.0	12568.0	12840.0	13394.0	13933.0	15750.0	18480.0	20960.0
Tot. Domestic Consumption	11814.0	12205.0	12523.0	12768.0	13040.0	13594.0	14133.0	15950.0	18680.0	21160.0
Interprovincial Transfers (net)	-292.0	-460.0	-300.0	-300.0	-300.0	-300.0	-300.0	-300.0	-300.0	-300.0
Exports (net)	20.0	70.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table A4-5 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Alberta

Low Price Case

(Gigawatt hours) Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous	610.0	654.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	25158.0	25948.0	27659.0	27566.0	27820.0	28563.0	29329.0	33949.0	37426.0	41177.0
-Lignite										
Oil Fired Steam										
-Light	2.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	75.0	79.0	70.0	50.0	40.0	30.0	20.0	20.0	20.0	20.0
Natural Gas Fired Steam	1420.0	2580.0	1561.0	1554.0	1580.0	1227.0	1301.0	1870.0	1882.0	2167.0
Comb. Turbines										
-Light Oil										
-Natural Gas	1510.0	1622.0	1000.0	1000.0	1000.0	1000.0	1000.0	1041.0	1032.0	1205.0
Internal Combustion										
-Diesel Oil	78.0	51.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0	163.0
Nuclear										
Hydroelectric	1427.0	1392.0	1636.0	1636.0	1636.0	1636.0	1636.0	1636.0	1636.0	1636.0
Other	879.0	924.0	900.0	900.0	900.0	1000.0	1000.0	1500.0	2000.0	2000.0
Total Energy Generation	31159.0	33252.0	32989.0	32869.0	33139.0	33619.0	34449.0	40179.0	44159.0	48368.0
Tot. Domestic Consumption	31196.0	33483.0	33290.0	33170.0	33240.0	33520.0	34050.0	39680.0	43860.0	48369.0
Interprovincial Transfers (net)	-35.0	-229.0	-301.0	-301.0	-301.0	-301.0	-401.0	-501.0	-701.0	-1001.0
Exports (Net)	-2.0	-2.0	0.0	0.0	200.0	400.0	800.0	1000.0	1000.0	1000.0

High Price Case

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous	610.0	654.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	25158.0	25948.0	28248.0	28705.0	29371.0	30996.0	32242.0	39729.0	46929.0	51898.0
-Lignite										
Oil Fired Steam										
-Light	2.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	75.0	79.0	70.0	50.0	40.0	30.0	20.0	20.0	20.0	20.0
Natural Gas Fired Steam	1420.0	2580.0	1753.0	1966.0	2186.0	1722.0	2030.0	2970.0	2064.0	2119.0
Comb. Turbines										
-Light Oil										
-Natural Gas	1510.0	1622.0	1000.0	1000.0	1014.0	1003.0	1040.0	1337.0	1098.0	1234.0
Internal Combustion										
-Diesel Oil	78.0	51.0	163.0	163.0	163.0	163.0	163.0	171.0	163.0	163.0
Nuclear										
Hydroelectric	1427.0	1392.0	1636.0	1636.0	1636.0	1636.0	1636.0	1636.0	1636.0	1636.0
Other	879.0	924.0	900.0	900.0	900.0	1000.0	1000.0	1500.0	2000.0	2000.0
Total Energy Generation	31159.0	33252.0	33770.0	34420.0	35310.0	36550.0	38131.0	47363.0	53910.0	59070.0
Tot. Domestic Consumption	31196.0	33483.0	34080.0	34730.0	35420.0	36360.0	37541.0	45873.0	51620.0	57080.0
Interprovincial Transfers (net)	-35.0	-229.0	-310.0	-310.0	-310.0	-310.0	-410.0	-510.0	-710.0	-1010.0
Exports (Net)	-2.0	-2.0	0.0	0.0	200.0	500.0	1000.0	2000.0	3000.0	3000.0

(Gigawatt hours)

Prairies
Low Price Case

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous	610.0	654.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	25184.0	25976.0	27724.0	27631.0	27885.0	28628.0	29394.0	34014.0	37491.0	41242.0
-Lignite	9222.0	9575.0	8017.0	8339.0	8482.0	8954.0	9113.0	10585.0	12912.0	16146.0
Oil Fired Steam										
-Light	16.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	137.0	138.0	135.0	115.0	105.0	95.0	55.0	55.0	55.0	55.0
Natural Gas Fired Steam	1916.0	2880.0	1821.0	1821.0	1851.0	1515.0	1642.0	2208.0	2247.0	2491.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	1547.0	1667.0	1046.0	1069.0	1076.0	1114.0	1160.0	1143.0	1218.0	1302.0
Internal Combustion										
-Diesel Oil	137.0	112.0	221.0	221.0	221.0	221.0	221.0	221.0	221.0	221.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	24356.0	25694.0	26738.0	26738.0	26738.0	26748.0	27802.0	33644.0	40385.0	42332.0
Other	1063.0	1096.0	1080.0	1080.0	1080.0	1180.0	1200.0	1710.0	2230.0	2280.0
Total Energy Generation	64188.0	67808.0	66782.0	67014.0	67438.0	68455.0	70587.0	83580.0	96759.0	106069.0
Tot. Domestic Consumption	58252.0	61432.0	62427.0	63259.0	63832.0	64899.0	66181.0	76270.0	85849.0	96559.0
Exports (Net)	5031.0	5783.0	3650.0	2950.0	2800.0	2750.0	3700.0	6604.0	10304.0	9204.0

High Price Case

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous	610.0	654.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	25184.0	25976.0	28313.0	28770.0	29436.0	31061.0	32307.0	39794.0	46994.0	51963.0
-Lignite	9222.0	9575.0	8041.0	8370.0	8705.0	9202.0	9484.0	11542.0	14099.0	16680.0
Oil Fired Steam										
-Light	16.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	137.0	138.0	135.0	115.0	105.0	95.0	55.0	55.0	55.0	55.0
Natural Gas Fired Steam	1916.0	2880.0	2014.0	2236.0	2467.0	2029.0	2397.0	3279.0	2397.0	2471.0
Comb. Turbines										
-Light Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	1547.0	1667.0	1047.0	1074.0	1105.0	1155.0	1255.0	1381.0	1210.0	1419.0
Internal Combustion										
-Diesel Oil	137.0	112.0	221.0	221.0	221.0	221.0	221.0	229.0	221.0	221.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	24356.0	25694.0	26738.0	26738.0	26738.0	26748.0	27802.0	33644.0	40385.0	42332.0
Other	1063.0	1096.0	1080.0	1080.0	1080.0	1180.0	1200.0	1710.0	2230.0	2280.0
Total Energy Generation	64188.0	67808.0	67589.0	68604.0	69857.0	71691.0	74721.0	91634.0	107591.0	117421.0
Tot. Domestic Consumption	58252.0	61432.0	63243.0	64758.0	66060.0	67944.0	69924.0	83333.0	94390.0	105420.0
Exports (Net)	5031.0	5783.0	3650.0	3050.0	3000.0	2950.0	4100.0	7604.0	12604.0	11704.0

Table A4-5 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

British Columbia

Low Price Case

(Gigawatt hours) Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous										
-Sub-Bituminous										
-Lignite										
Oil Fired Steam										
-Light										
-Heavy	554.0	520.0	555.0	565.0	575.0	585.0	595.0	550.0	500.0	500.0
Natural Gas Fired Steam	704.0	658.0	709.0	746.0	770.0	888.0	1064.0	1389.0	1672.0	2253.0
Comb. Turbines										
-Light Oil	144.0	141.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0
Internal Combustion										
-Diesel Oil	73.0	72.0	274.0	274.0	274.0	274.0	274.0	249.0	249.0	257.0
Nuclear										
Hydroelectric	50232.0	57105.0	56299.0	56275.0	56299.0	56299.0	56299.0	60751.0	67462.0	74361.0
Other	671.0	630.0	800.0	855.0	910.0	965.0	1020.0	1350.0	1400.0	1400.0
Total Energy Generation	52378.0	59126.0	58637.0	58715.0	58828.0	59011.0	59252.0	64289.0	71283.0	78835.0
Tot. Domestic Consumption	45625.0	48681.0	51022.0	51600.0	52613.0	53596.0	54337.0	57424.0	64318.0	72370.0
Interprovincial Transfers (net)	31.0	226.0	301.0	301.0	301.0	301.0	401.0	501.0	701.0	1001.0
Exports (Net)	6722.0	10219.0	7315.0	6815.0	5915.0	5115.0	4515.0	6365.0	6265.0	5464.0

High Price Case

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous										
-Sub-Bituminous										
-Lignite										
Oil Fired Steam										
-Light										
-Heavy	554.0	520.0	555.0	565.0	575.0	585.0	595.0	550.0	500.0	500.0
Natural Gas Fired Steam	704.0	658.0	700.0	700.0	700.0	700.0	741.0	779.0	2247.0	1859.0
Comb. Turbines										
-Light Oil	144.0	141.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas										
Internal Combustion										
-Diesel Oil	73.0	72.0	274.0	274.0	274.0	274.0	274.0	249.0	249.0	249.0
Nuclear										
Hydroelectric	50232.0	57105.0	56222.0	56200.0	56247.0	56294.0	56299.0	60751.0	60751.0	67462.0
Other	671.0	630.0	800.0	855.0	910.0	965.0	1020.0	1350.0	1400.0	1400.0
Total Energy Generation	52378.0	59126.0	58551.0	58594.0	58706.0	58818.0	58929.0	63679.0	65147.0	71470.0
Tot. Domestic Consumption	45625.0	48681.0	50736.0	50779.0	51391.0	52003.0	52314.0	54414.0	59582.0	65005.0
Interprovincial Transfers (net)	31.0	226.0	310.0	310.0	310.0	310.0	410.0	510.0	710.0	1010.0
Exports (Net)	6722.0	10219.0	7505.0	7505.0	7005.0	6505.0	6205.0	8755.0	4855.0	5455.0

Yukon

Low Price Case

(Gigawatt hours)

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous										
-Sub-Bituminous										
-Lignite										
Oil Fired Steam										
-Light										
-Heavy										
Natural Gas Fired Steam										
Comb. Turbines										
-Light Oil										
-Natural Gas										
Internal Combustion										
-Diesel Oil	22.0	24.0	38.0	38.0	39.0	39.0	39.0	39.0	39.0	40.0
Nuclear										
Hydroelectric	232.0	233.0	220.0	221.0	221.0	222.0	223.0	228.0	233.0	237.0
Other										
Total Energy Generation	254.0	257.0	258.0	259.0	260.0	261.0	262.0	267.0	272.0	277.0
Tot. Domestic Consumption	254.0	257.0	258.0	259.0	260.0	261.0	262.0	267.0	272.0	277.0
Interprovincial Transfers (net)										
Exports (Net)										

High Price Case

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous										
-Sub-Bituminous										
-Lignite										
Oil Fired Steam										
-Light										
-Heavy										
Natural Gas Fired Steam										
Comb. Turbines										
-Light Oil										
-Natural Gas										
Internal Combustion										
-Diesel Oil	22.0	24.0	38.0	38.0	38.0	38.0	39.0	41.0	44.0	50.0
Nuclear										
Hydroelectric	232.0	233.0	204.0	209.0	214.0	219.0	223.0	248.0	275.0	302.0
Other										
Total Energy Generation	254.0	257.0	242.0	247.0	252.0	257.0	262.0	289.0	319.0	352.0
Tot. Domestic Consumption	254.0	257.0	242.0	247.0	252.0	257.0	262.0	289.0	319.0	352.0
Interprovincial Transfers (net)										
Exports (Net)										

Table A4-5 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

Northwest Territories
Low Price Case

(Gigawatt hours) Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous										
-Sub-Bituminous										
-Lignite										
Oil Fired Steam										
-Light										
-Heavy										
Natural Gas Fired Steam										
Comb. Turbines										
-Light Oil										
-Natural Gas										
Internal Combustion										
-Diesel Oil	206.0	182.0	207.0	208.0	244.0	260.0	268.0	336.0	427.0	535.0
Nuclear										
Hydroelectric	317.0	327.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0
Other										
Total Energy Generation	523.0	509.0	510.0	511.0	547.0	563.0	571.0	639.0	730.0	838.0
Tot. Domestic Consumption	523.0	509.0	510.0	511.0	547.0	563.0	571.0	639.0	730.0	838.0
Interprovincial Transfers (net)										
Exports (Net)										

High Price Case

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous										
-Sub-Bituminous										
-Lignite										
Oil Fired Steam										
-Light										
-Heavy										
Natural Gas Fired Steam										
Comb. Turbines										
-Light Oil										
-Natural Gas										
Internal Combustion										
-Diesel Oil	206.0	182.0	199.0	212.0	225.0	238.0	251.0	324.0	407.0	500.0
Nuclear										
Hydroelectric	317.0	327.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0	303.0
Other										
Total Energy Generation	523.0	509.0	502.0	515.0	528.0	541.0	554.0	627.0	710.0	803.0
Tot. Domestic Consumption	523.0	509.0	502.0	515.0	528.0	541.0	554.0	627.0	710.0	803.0
Interprovincial Transfers (net)										
Exports (Net)										

Table A4-5 (Continued)
Energy Generation by Fuel Type - Canada, Provinces and Territories

British Columbia, Yukon and Northwest Territories

(Gigawatt hours)

Low Price Case

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	554.0	520.0	555.0	565.0	575.0	585.0	595.0	550.0	500.0	500.0
Natural Gas Fired Steam	704.0	658.0	709.0	746.0	770.0	888.0	1064.0	1389.0	1672.0	2253.0
Comb. Turbines										
-Light Oil	144.0	141.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0
Internal Combustion										
-Diesel Oil	301.0	278.0	519.0	520.0	557.0	573.0	581.0	624.0	715.0	832.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	50781.0	57665.0	56822.0	56799.0	56823.0	56824.0	56825.0	61282.0	67998.0	74901.0
Other	671.0	630.0	800.0	855.0	910.0	965.0	1020.0	1350.0	1400.0	1400.0
Total Energy Generation	53155.0	59892.0	59405.0	59485.0	59635.0	59835.0	60085.0	65195.0	72285.0	79950.0
Tot. Domestic Consumption	46402.0	49447.0	51790.0	52370.0	53420.0	54420.0	55170.0	58330.0	65320.0	73485.0
Exports (Net)	6722.0	10219.0	7315.0	6815.0	5915.0	5115.0	4515.0	6365.0	6265.0	5465.0

High Price Case

Type of Generation	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Coal Fired Steam										
-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Sub-Bituminous	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Lignite	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil Fired Steam										
-Light	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Heavy	554.0	520.0	555.0	565.0	575.0	585.0	595.0	550.0	500.0	500.0
Natural Gas Fired Steam	704.0	658.0	700.0	700.0	700.0	700.0	741.0	779.0	2247.0	1859.0
Comb. Turbines										
-Light Oil	144.0	141.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
-Natural Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Internal Combustion										
-Diesel Oil	301.0	278.0	511.0	524.0	537.0	550.0	564.0	614.0	700.0	799.0
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	50781.0	57665.0	56729.0	56712.0	56764.0	56816.0	56825.0	61302.0	61329.0	68067.0
Other	671.0	630.0	800.0	855.0	910.0	965.0	1020.0	1350.0	1400.0	1400.0
Total Energy Generation	53155.0	59892.0	59295.0	59356.0	59486.0	59616.0	59745.0	64595.0	66176.0	72625.0
Tot. Domestic Consumption	46402.0	49447.0	51480.0	51541.0	52171.0	52801.0	53130.0	55330.0	60611.0	66160.0
Exports (Net)	6722.0	10219.0	7505.0	7505.0	7005.0	6505.0	6205.0	8755.0	4855.0	5455.0

Table A4-6
Demand for Fuel Sources for Generation of Electricity - Canada

(Petajoules)	Low Price Case									
	1984	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Coal[a]										
-Bituminous	436.1	373.4	364.0	344.5	275.9	280.5	306.1	458.5	753.4	961.3
-Sub-Bituminous	276.0	284.7	303.9	303.0	305.7	313.8	322.3	372.9	411.0	452.0
-Lignite	141.5	143.4	119.9	124.3	126.3	132.9	134.9	155.0	186.7	231.1
-Total Coal	853.6	801.5	787.8	771.8	707.9	727.2	763.3	986.4	1351.1	1644.4
Oil[a]										
-Light	4.2	3.9	0.7	0.7	0.7	0.7	1.2	3.7	3.6	14.6
-Heavy	52.4	61.1	64.2	66.0	74.4	82.3	56.4	37.1	35.1	83.2
-Diesel	9.4	7.8	12.7	12.7	13.6	13.8	14.0	15.0	16.2	18.1
-Total Oil	66.0	72.8	77.6	79.4	88.7	96.8	71.6	55.8	54.9	115.9
Natural Gas[a]	49.0	61.6	38.6	40.4	41.5	39.7	43.7	55.0	60.2	71.4
Uranium[b]	595.9	694.0	785.7	900.7	1059.6	1134.7	1209.8	1359.9	1358.2	1517.7
Hydroelectric[c]	1019.9	1087.5	1132.4	1168.6	1178.9	1163.3	1186.5	1287.4	1419.8	1550.3
Other	22.7	23.4	25.3	26.4	27.1	29.0	30.4	40.7	47.1	48.6
Total Energy Generation	2607.1	2740.8	2847.4	2987.3	3103.7	3190.7	3305.3	3785.2	4291.3	4948.3
	High Price Case									
Coal[a]										
-Bituminous	436.1	373.6	345.5	312.6	247.7	228.0	263.6	421.9	633.2	777.3
-Sub-Bituminous	276.0	284.7	310.3	315.4	322.7	340.5	354.1	436.2	515.1	569.6
-Lignite	141.5	143.2	120.2	124.8	129.4	136.2	140.0	168.1	202.9	238.3
-Total Coal	853.6	801.5	776.0	752.8	699.8	704.7	757.7	1026.2	1351.2	1585.2
Oil[a]										
-Light	4.2	3.9	0.6	0.7	0.9	1.3	3.6	2.1	3.7	9.1
-Heavy	52.4	61.1	65.3	70.6	77.3	87.1	65.2	28.3	31.3	38.2
-Diesel	9.4	7.8	12.6	12.8	13.3	13.6	14.0	14.9	16.1	17.9
-Total Oil	66.0	72.8	78.5	84.1	91.5	102.0	82.8	45.3	51.1	65.2
Natural Gas[a]	49.0	61.6	40.8	45.1	48.7	44.4	50.9	65.4	68.6	68.3
Uranium[b]	595.9	694.0	788.8	903.8	1062.7	1137.9	1212.9	1363.0	1361.3	1600.5
Hydroelectric[c]	1019.9	1087.5	1142.4	1171.0	1182.3	1164.9	1188.4	1288.6	1386.7	1511.7
Other	22.7	23.4	25.3	26.4	27.1	29.0	30.4	40.7	47.1	48.6
Total Energy Generation	2607.1	2740.8	2851.8	2983.2	3112.1	3182.9	3323.1	3829.2	4266.0	4879.5

Note: [a] Converted to petajoules from thermal generation based on plant specific factors.

[b] Converted to petajoules from nuclear generation based on a rate of 12.1. PJ/TW.h.

[c] Converted to petajoules from hydro generation based on a rate of 3.6. PJ/TW.h.

Table A4-7
Net Electricity Exports - Canada and Provinces

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
					Low Price Case					
					(Gigawatt hours)					
Province or Territory										
New Brunswick	5639	6251	7293	7293	7293	7293	7293	7043	8443	8545
Quebec	11242	9603	15120	23550	23550	26550	29050	23650	20450	16650
Ontario	10457	8864	6145	6381	6189	6704	8400	8672	10536	10187
Manitoba	5013	5715	3550	2850	2500	2250	2800	5504	9204	8104
Saskatchewan	20	70	100	100	100	100	100	100	100	100
Alberta	-2	-2	0	0	200	400	800	1000	1000	1000
British Columbia	6722	10219	7315	6815	5915	5115	4515	6365	6265	5464
Canada	39091	40720	39523	46989	45747	48412	52958	52334	55998	50050
					(Petajoules) [a]					
Province or Territory										
New Brunswick	41.5	42.1	41.8	41.8	41.8	41.8	41.8	68.4	79.0	82.7
Quebec	40.5	34.6	54.4	84.8	84.8	95.6	104.6	85.1	73.6	59.8
Ontario	98.7	83.6	58.3	61.1	61.5	67.7	85.5	88.8	100.7	96.5
Manitoba	18.0	20.6	12.8	10.3	9.0	8.1	10.1	19.8	33.1	29.2
Saskatchewan	0.3	1.0	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Alberta	0.0	0.0	0.0	0.0	1.7	3.4	6.8	8.4	8.4	8.4
British Columbia	24.2	36.8	26.3	24.5	21.3	18.4	16.3	22.9	22.6	19.7
Canada	223.2	218.7	195.1	224.0	221.6	236.5	266.6	294.9	318.9	297.8
					High Price Case					
					(Gigawatt hours)					
Province or Territory										
New Brunswick	5639	6251	8220	7625	7625	7625	7625	8193	8398	8198
Quebec	11242	9603	18050	25550	25550	26550	31550	28750	19650	16950
Ontario	10457	8864	6149	6435	8479	9233	10303	9722	11929	12620
Manitoba	5013	5715	3550	2950	2700	2350	3000	5504	9504	8604
Saskatchewan	20	70	100	100	100	100	100	100	100	100
Alberta	-2	-2	0	0	200	500	1000	2000	3000	3000
British Columbia	6722	10219	7505	7505	5005	6505	6205	8755	4855	5455
Canada	39091	40720	43574	50165	49659	52863	59783	63024	57436	54927
					(Petajoules) [a]					
Province or Territory										
New Brunswick	41.5	42.1	47.6	45.5	45.5	45.5	45.5	75.0	78.0	75.0
Quebec	40.5	34.6	65.0	92.0	92.0	95.6	113.5	103.5	70.7	61.0
Ontario	98.7	83.6	58.3	61.8	83.8	92.9	106.0	101.5	114.8	120.5
Manitoba	18.0	20.6	12.8	10.6	9.7	8.5	10.8	19.8	34.2	31.0
Saskatchewan	0.3	1.0	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Alberta	0.0	0.0	0.0	0.0	1.7	4.2	8.4	16.9	25.3	25.3
British Columbia	24.2	36.8	27.0	27.0	25.2	23.4	22.3	31.5	17.5	19.6
Canada	223.2	218.7	212.2	238.4	259.4	271.6	308.0	349.7	342.0	333.9

Note: [a] Converted from gigawatt hours using plant specific factors for fossil fuels, and 3.6. PJ/TW.h for hydro and 12.1 PJ/TW.h for nuclear.

Table A4-8
Net Electricity Exports by Fuel Type - Canada

(Terawatt hours)	Low Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Type of Fuel										
Hydro	26.1	29.5	31.3	38.5	37.2	39.2	41.7	38.1	39.5	33.6
Coal	10.7	9.2	6.4	6.4	5.6	5.8	7.2	9.8	14.3	14.6
Nuclear	1.7	1.7	1.8	2.1	2.9	3.4	4.1	4.4	2.2	1.9
Oil	0.6	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	39.1	40.7	39.5	47.0	45.7	48.4	53.0	52.3	56.0	50.1
	High Price Case									
Type of Fuel										
Hydro	26.1	29.5	35.3	41.6	40.9	41.0	46.4	46.7	37.7	34.7
Coal	10.7	9.2	6.4	6.4	7.6	7.9	8.4	10.8	17.0	17.8
Nuclear	1.7	1.7	1.9	2.2	3.2	4.0	5.0	5.5	2.7	2.4
Oil	0.6	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	39.1	40.7	43.6	50.2	51.7	52.9	59.8	63.0	57.4	54.9

Appendix 5

Table A5-1
Historical Data - Established Reserves and Cumulative Production of Marketable Natural Gas
Conventional Areas

(Exajoules)

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Initial Reserves	58.49	59.84	64.80	67.85	74.77	77.10	82.86	83.20	87.42	89.20
Cumulative Production	7.94	9.19	10.61	12.03	13.93	15.73	18.25	20.77	23.48	26.17
Remaining Reserves	50.55	50.65	54.19	55.82	60.84	61.37	64.61	62.43	63.94	63.03

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Initial Reserves	91.07	96.29	102.70	110.94	115.94	119.16	126.52	129.97	131.33	132.85
Cumulative Production	28.88	31.42	34.25	36.89	40.00	42.77	45.74	48.52	51.30	54.28
Remaining Reserves	62.19	64.87	68.45	74.05	75.94	76.39	80.78	81.45	80.03	78.57

Table A5-2
Historical Data and Projections - Gas Directed Exploratory Drilling and Reserves Additions of Marketable Natural Gas - Conventional Areas

	Drilling (Millions of Metres) (1)	Reserves Added (Exajoules) (2)	Additions Rate (Petajoules per kilometre) (3)
1965	0.76	4.80	6.32
1966	0.85	1.34	1.58
1967	0.68	4.96	7.29
1968	0.91	3.04	3.34
1969	0.88	6.92	7.86
1970	1.24	2.34	1.89
1971	1.11	5.76	5.19
1972	1.56	0.34	0.22
1973	1.69	4.22	2.50
1974	1.49	1.78	1.19
1975	1.34	1.87	1.40
1976	1.87	5.22	2.79
1977	2.21	6.41	2.90
1978	2.63	8.23	3.13
1979	2.78	5.00	1.80
1980	3.50	3.22	0.92
1981	2.67	7.36	2.76
1982	1.58	3.45	2.18
1983	1.14	1.36	1.19
1984	1.43	1.52	1.06

	Low Price Case (4)	High Price Case (5)	Low Price Case (6)	High Price Case (7)	Low Price Case (8)	High Price Case (9)
1985	1.42	1.42	1.37	1.37	0.96	0.96
1986	0.98	0.98	1.46	1.46	1.49	1.49
1987	0.68	0.83	0.99	1.20	1.46	1.45
1988	0.66	0.85	0.94	1.21	1.42	1.42
1989	0.72	1.02	1.00	1.40	1.39	1.37
1990	0.84	1.25	1.13	1.66	1.35	1.33
1995	1.08	2.55	1.25	2.48	1.16	0.97
2000	0.68	2.70	0.68	1.73	1.00	0.64
2005	0.41	2.66	0.38	1.11	0.93	0.42
Reserves Additions Total (1985-2005)			20.02	36.68		

Table A5-3
Historical Data - Natural Gas Supply and Demand - Conventional Areas

(Petajoules)	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Sectoral Demand										
Residential	201.5	208.0	215.2	227.1	244.1	255.1	264.8	296.5	286.6	309.0
Commercial	111.3	126.2	140.0	159.1	191.7	203.3	232.5	280.7	269.2	300.2
Petrochemical	44.4	52.5	56.1	60.0	70.7	86.9	90.4	87.2	92.8	95.6
Other Industrial	188.2	213.8	241.3	272.7	309.6	333.9	387.0	428.6	463.6	518.0
Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total End Use	545.5	600.5	652.6	719.0	816.1	879.2	974.7	1092.9	1112.3	1222.7
Own Use	0.0	0.0	0.0	0.0	0.0	81.7	92.7	107.5	112.8	117.6
Electricity Generation	64.7	69.5	72.6	85.3	64.2	99.0	100.1	147.7	200.2	173.2
Steam Production	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Conversions	3.0	5.0	4.0	5.0	5.0	5.0	8.0	11.0	10.0	11.0
Total Primary Demand	613.1	675.0	729.3	809.3	885.3	1064.9	1175.5	1359.2	1435.3	1524.5
Reprocessing Shrinkage	26.0	29.0	27.0	29.0	36.0	44.0	55.0	74.0	81.0	78.0
Domestic Demand	639.1	704.0	756.3	838.3	921.3	1108.9	1230.5	1433.2	1516.3	1602.5
Exports	445.0	475.0	564.0	664.0	748.0	858.0	1003.0	1110.0	1130.0	1054.0
Total Disposition [a]	1084.1	1179.0	1320.3	1502.3	1669.3	1966.9	2233.5	2543.2	2646.3	2656.5
Total Production	1140.0	1224.0	1341.0	1514.0	1769.0	2037.0	2260.0	2569.0	2741.0	2687.0
Productive Capacity [b]	-	-	-	1550.0	1800.0	2100.0	2400.0	2600.0	2750.0	2900.0

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Sectoral Demand										
Residential	315.6	329.9	331.0	403.0	415.5	426.8	430.7	483.8	469.3	487.5
Commercial	307.7	330.9	352.7	344.5	353.3	333.1	356.0	392.5	386.8	401.1
Petrochemical	104.4	123.6	166.8	175.6	192.9	195.2	175.7	208.8	251.7	290.3
Other Industrial	480.3	542.0	566.1	572.7	592.5	602.0	573.2	499.4	498.9	564.7
Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total End Use	1208.0	1326.5	1416.6	1495.8	1554.2	1557.1	1535.6	1584.5	1606.7	1743.5
Own Use	116.2	122.8	124.1	119.4	126.4	118.5	117.1	115.2	119.7	127.4
Electricity Generation	195.3	139.1	132.0	106.4	104.1	84.0	68.6	61.0	75.2	67.5
Steam Production	0.0	0.0	0.0	0.0	0.0	0.4	0.1	0.0	0.0	0.0
Other Conversions	11.0	11.0	12.0	14.0	15.0	16.0	17.0	16.0	11.5	10.9
Total Primary Demand	1530.5	1599.4	1684.7	1735.6	1799.7	1776.0	1738.4	1776.6	1813.1	1949.3
Reprocessing Shrinkage	77.0	74.0	71.0	69.0	102.0	155.0	162.0	160.0	153.0	181.0
Domestic Demand	1607.5	1673.4	1755.7	1804.6	1901.7	1931.0	1900.4	1936.6	1966.1	2130.3
Exports	1019.0	1027.0	1077.0	949.0	1094.0	863.0	824.0	845.0	764.0	812.0
Total Disposition [a]	2626.5	2700.4	2832.7	2753.6	2995.7	2794.0	2724.4	2781.6	2730.1	2942.3
Total Production	2728.0	2754.0	2872.0	2777.0	3007.0	2764.0	2739.0	2807.0	2664.0	2901.0
Productive Capacity [b]	3050.0	3200.0	3400.0	3650.0	4000.0	4400.0	4600.0	4850.0	5030.0	4850.0

Notes: [a] Total disposition differs from total production because of:
- synthetic natural gas and imports in disposition but not in production of natural gas;
- inventory changes; and
- statistical differences.

[b] Estimated from previous reports.

Table A5-4
Connection Rates for Gas Reserves

(Percent of reserves connected in year)

Year After Addition	Low Price Case: Uncontracted Alberta Reserves (1)	Low Price Case: Reserves Additions (2)	High Price Case: Uncontracted Alberta Reserves (3)	High Price Case: Reserves Additions (4)
0	5	10	5	10
1	5	10	5	15
2	5	15	10	20
3	10	20	15	25
4	10	20	15	15
5	15	10	15	5
6	15	5	15	5
7	15	5	10	5
8	10	5	5	-
9	10	-	5	-
Total	100	100	100	100

Table A5-5
Productive Capacity from Established Reserves of Natural Gas - Canada

(Petajoules) Low Price Case

	Total Contracted (1)	S.E. Alta. Uncontracted (2)	Other Alta. Uncontracted (3)	B.C. Uncontracted (4)	Sask. Uncontracted (5)	Alberta Deferred (6)	Total (7)
1985	4580	19	36	9	36	1	4681
1986	4527	38	71	9	34	2	4681
1987	4357	56	107	14	32	3	4569
1988	4128	94	178	33	30	3	4466
1989	3830	130	249	50	29	4	4292
1990	3479	183	355	57	27	6	4107
1991	3122	231	460	63	26	7	3909
1992	2754	276	562	73	25	9	3699
1993	2390	299	624	81	24	18	3436
1994	2045	315	683	85	22	27	3177
1995	1747	289	661	95	21	35	2848
1996	1470	256	631	113	20	43	2533
1997	1246	221	594	138	19	52	2270
1998	1005	185	547	142	18	58	1955
1999	818	153	494	140	17	62	1684
2000	683	124	436	138	16	68	1465
2001	563	104	378	132	16	72	1265
2002	483	86	327	127	15	77	1115
2003	400	70	288	125	14	81	978
2004	346	56	253	118	13	85	871
2005	278	43	229	121	13	88	772
Total	44251	3228	8163	1863	467	801	58773

Table A5-5 (Continued)
Productive Capacity from Established Reserves of Natural Gas - Canada

(Petajoules) High Price Case

	Total Contracted (1)	S.E. Alta. Uncontracted (2)	Other Alta. Uncontracted (3)	B.C. Uncontracted (4)	Sask. Uncontracted (5)	Alberta Deferred (6)	Total (7)
1985	4580	19	38	9	36	1	4683
1986	4602	38	59	9	34	2	4744
1987	4573	75	118	14	32	3	4815
1988	4331	131	206	34	30	3	4735
1989	4021	186	294	50	29	4	4584
1990	3658	239	382	58	27	6	4370
1991	3287	285	470	63	26	7	4138
1992	2897	309	528	73	25	9	3841
1993	2519	305	557	82	24	18	3505
1994	2156	294	585	86	22	27	3170
1995	1844	261	584	100	21	35	2845
1996	1548	225	583	117	20	43	2536
1997	1309	190	581	139	19	52	2290
1998	1055	159	580	144	18	58	2014
1999	852	132	578	145	17	62	1786
2000	702	108	575	143	16	68	1612
2001	577	90	572	139	16	72	1466
2002	505	73	567	134	15	77	1371
2003	416	58	559	131	14	81	1259
2004	353	45	536	124	13	85	1156
2005	285	34	502	125	13	88	1047
Total	46070	3256	9454	1919	467	801	61967

Table A5-6
Productive Capacity of Natural Gas from All Sources

(Petajoules)

Low Price Case

	Established Reserves	Reserves Additions				Western Canada
	Total	British Columbia	Alberta	Saskatchewan	Total	Total
	(1)	(2)	(3)	(4)	(5)	(6)
1985	4681	0	8	3	11	4692
1986	4681	2	25	6	33	4714
1987	4569	6	52	10	68	4637
1988	4466	13	92	16	121	4587
1989	4292	24	145	21	190	4482
1990	4107	38	200	24	262	4369
1991	3909	55	255	25	335	4244
1992	3699	73	312	24	409	4108
1993	3436	92	373	23	488	3924
1994	3177	111	435	21	567	3744
1995	2848	129	494	17	640	3488
1996	2533	145	549	15	709	3242
1997	2270	158	599	13	770	3040
1998	1955	169	641	11	821	2776
1999	1684	176	676	9	861	2545
2000	1465	179	702	7	888	2353
2001	1265	180	721	6	907	2172
2002	1115	179	731	5	915	2030
2003	978	175	732	3	910	1888
2004	871	170	726	3	899	1770
2005	772	164	711	2	877	1649
Total	58773	2238	9179	264	11681	70454

Table A5-6 (Continued)
Productive Capacity of Natural Gas from All Sources

(Petajoules) High Price Case

	Established Reserves	Reserves Additions				Western Canada	Frontier		Total Canada
	Total	British Columbia	Alberta	Saskatchewan	Total	Total	Scotian Shelf	Mackenzie Delta	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1985	4683	0	6	3	9	4692	-	-	4692
1986	4744	2	20	7	29	4773	-	-	4773
1987	4815	5	45	13	63	4878	-	-	4878
1988	4735	11	82	21	114	4849	-	-	4849
1989	4584	21	127	28	176	4760	-	-	4760
1990	4370	33	174	32	239	4609	31	-	4640
1991	4138	47	226	36	309	4447	126	-	4573
1992	3841	63	288	39	390	4231	129	-	4360
1993	3505	80	359	39	478	3983	133	-	4116
1994	3170	99	438	39	576	3746	133	-	3879
1995	2845	117	526	38	681	3526	133	320	3979
1996	2536	135	621	37	793	3329	133	320	3782
1997	2290	152	718	36	906	3196	133	320	3649
1998	2014	168	815	34	1017	3031	133	320	3484
1999	1786	182	910	32	1124	2910	133	320	3363
2000	1612	196	1001	31	1228	2840	133	320	3293
2001	1466	208	1086	29	1323	2789	127	320	3236
2002	1371	219	1165	27	1411	2782	117	320	3219
2003	1259	229	1237	25	1491	2750	102	320	3172
2004	1156	237	1298	23	1558	2714	89	320	3123
2005	1047	244	1347	21	1612	2659	78	320	3057
Total	61967	2448	12489	590	15527	77494	1863	3520	82877

Table A5-7
Historical Data and Projections
Licensed Natural Gas Exports by United States Regional Markets

(Billions of Cubic Meters)

	Pacific Northwest	Mountain	California	Central	Northeast	Total Exports	Total Authorized	Exports As Percent of Authorized
1965	3.2	1.8	4.3	2.1	0.1	11.5	-	-
1966	3.3	2.0	4.7	2.2	0.0	12.2	-	-
1967	4.0	2.2	5.8	2.4	0.1	14.5	-	-
1968	4.2	2.4	6.7	3.4	0.4	17.1	-	-
1969	4.7	2.7	7.5	3.9	0.5	19.3	-	-
1970	4.9	2.8	8.6	5.0	0.8	22.1	-	-
1971	5.2	3.0	10.0	6.9	0.7	25.8	25.8	100
1972	6.5	3.6	10.9	7.3	0.3	28.6	30.3	94
1973	6.8	3.7	11.0	7.4	0.2	29.1	29.6	98
1974	6.2	3.4	10.1	7.2	0.3	27.2	29.4	93
1975	5.5	3.1	10.8	7.1	0.3	26.8	29.0	92
1976	5.5	2.9	11.1	7.2	0.3	27.0	29.2	92
1977	6.1	2.9	11.1	7.9	0.3	28.3	30.0	94
1978	5.3	2.6	9.8	7.1	0.2	25.0	29.1	86
1979	5.9	2.8	11.0	8.1	0.5	28.3	29.6	96
1980	4.1	2.0	8.9	7.0	0.6	22.6	32.4	70
1981	3.5	1.8	7.7	7.0	1.6	21.6	41.5	52
1982	2.3	1.3	8.8	7.8	2.0	22.2	46.7	48
1983	2.3	0.9	8.1	7.4	1.5	20.2	47.1	43
1984	1.9	0.8	7.9	7.8	2.9	21.3	47.1	45
1985	2.4	1.0	11.0	9.2	2.1	25.7	46.9	55
1986	2.3	1.0	9.7	7.8	1.8	22.6	46.8	48
1987	2.4	1.0	11.0	9.4	3.0	26.8	47.9	56
1988	2.8	1.2	11.4	11.2	5.7	32.3	54.2	60
1989	3.6	1.4	11.5	12.7	9.7	38.9	54.2	72
1990	4.0	1.6	11.5	11.9	8.7	37.7	48.1	78
1995	0.4	0.2	1.5	5.1	6.8	14.0	18.9	74
2000	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0
2005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0

Note: Data on total authorized volumes begins in 1971.

In addition to the volumes which were exported under licences, the following volumes were exported under short-term Orders:

(Billions of cubic metres)

1984 0.1
1985 0.5

Table A5-8

Natural Gas Supply and Demand - Canada - Conventional Areas

(Petajoules)

Low Price Case

	Net Sales (1)	Pipeline Fuel & Losses (2)	Reprocessing Fuel (3)	Primary Gas Demand (4)	Reprocessing Shrinkage (5)	Domestic Demand (6)	Exports (7)	Total Disposition (8)	Productive Capacity (9)	Adjusted Productive Capacity [a] (10)
1985	1910	133	13	2056	191	2247	991	3238	4692	4692
1986	1933	133	12	2078	186	2265	853	3118	4714	4707
1987	2020	145	14	2179	202	2381	1014	3395	4637	4688
1988	2110	163	15	2289	224	2513	1233	3746	4587	4634
1989	2198	184	17	2399	248	2648	1462	4109	4482	4593
1990	2238	183	17	2438	239	2677	1401	4078	4369	4506
1991	2275	178	16	2470	233	2702	1194	3896	4244	4406
1992	2321	173	16	2511	233	2744	960	3705	4108	4300
1993	2357	170	16	2544	232	2776	782	3557	3924	4189
1994	2404	170	16	2591	229	2819	692	3511	3744	4064
1995	2466	168	15	2650	216	2865	526	3391	3488	3908
1996	2516	166	14	2697	202	2898	355	3253	3242	3744
1997	2583	163	13	2759	184	2942	187	3129	3040	3525
1998	2627	159	13	2800	174	2972	89	3062	2776	3307
1999	2681	159	12	2854	172	3024	41	3065	2545	3109
2000	2743	159	12	2916	171	3086		3086	2353	2872
2001	2802	163	13	2979	173	3151		3151	2172	2628
2002	2880	168	13	3062	178	3238		3238	2030	2421
2003	2956	173	13	3144	182	3325		3325	1888	2235
2004	3022	177	14	3214	186	3398		3398	1770	2079
2005	3106	182	14	3303	189	3491		3491	1649	1937
Total	52148	3469	298	55933	4244	60162	11780	71942	70454	n.a.

Note: [a] Productive capacity adjusted to reflect that quantities produced equal total disposition.

Table A5-8 (Continued)
Natural Gas Supply and Demand - Canada - Conventional Areas

(Petajoules)

High Price Case

	Net Sales (1)	Pipeline Fuel & Losses (2)	Reprocessing Fuel (3)	Primary Gas Demand (4)	Reprocessing Shrinkage (5)	Domestic Demand (6)	Exports (7)	Total Disposition (8)	Productive Capacity (9)	Adjusted Productive Capacity [a] (10)
1985	1910	133	13	2056	191	2247	991	3238	4692	4692
1986	1941	133	12	2087	187	2273	853	3126	4773	4748
1987	2000	143	13	2156	199	2356	1014	3370	4878	4811
1988	2058	159	15	2232	219	2451	1233	3684	4849	4877
1989	2111	176	17	2305	241	2546	1462	4007	4760	4855
1990	2130	174	16	2320	230	2550	1401	3950	4609	4793
1991	2142	167	15	2325	222	2547	1194	3741	4447	4693
1992	2169	161	15	2345	220	2566	960	3526	4231	4572
1993	2183	156	15	2355	218	2571	782	3353	3983	4454
1994	2219	154	15	2389	213	2601	692	3292	3746	4283
1995	2260	151	14	2426	199	2624	526	3149	3526	4104
1996	2282	147	13	2444	184	2627	355	2982	3329	3922
1997	2333	144	12	2489	165	2652	187	2840	3196	3747
1998	2378	140	11	2530	155	2683	89	2772	3031	3570
1999	2425	139	11	2577	151	2726	41	2767	2910	3415
2000	2473	139	11	2624	150	2772		2772	2840	3280
2001	2516	141	11	2670	151	2819		2819	2789	3164
2002	2576	145	11	2734	154	2886		2886	2782	3020
2003	2632	148	11	2793	158	2949		2949	2750	2906
2004	2700	152	12	2865	160	3024		3024	2714	2837
2005	2750	155	12	2919	163	3080		3080	2659	2788
Total	48188	3157	275	51641	3930	55550	11780	67327	77494	n.a.

Note: [a] Productive capacity adjusted to reflect that quantities produced equal total disposition.

Appendix 6

Table A6-1

Historical Data - Initial Established Reserves and Remaining Reserves of Conventional Crude Oil

Conventional Areas

(Millions of Cubic Metres)

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Initial Reserves										
Light Crude Oil	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heavy Crude Oil	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	1960.4	2038.7	2154.2	2258.0	2324.5	2348.7	2387.5	2406.8	2416.9	2413.5
Remaining Reserves										
Light Crude Oil	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Heavy Crude Oil	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total	1528.3	1550.4	1610.5	1655.0	1659.2	1611.8	1573.4	1513.5	1420.6	1320.2

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Initial Reserves										
Light Crude Oil	1900.8	1890.0	1920.7	1939.4	1935.2	1935.4	1980.4	2055.1	2085.5	2164.8
Heavy Crude Oil	308.4	317.2	325.1	325.6	352.3	378.9	355.7	365.6	385.7	404.1
Total	2209.2	2207.2	2245.8	2265.0	2287.5	2314.3	2336.1	2420.7	2471.2	2568.9
Remaining Reserves										
Light Crude Oil	901.2	826.2	794.9	752.4	679.1	615.4	598.2	616.5	595.2	612.9
Heavy Crude Oil	128.1	127.9	124.4	114.1	128.4	144.3	117.3	119.2	123.8	127.7
Total	1029.3	954.1	919.3	866.5	807.5	759.7	715.5	735.7	719.0	740.6

N/A: Not available

Source: Canadian Petroleum Association 1965-1974
National Energy Board 1975-1984

Table A6-2
Established Reserves and Productive Capacity of Conventional Crude Oil
Conventional Areas

	Initial Recoverable Reserves at 31/12/84	Cumulative Production to 31/12/84	Remaining Reserves at 31/12/84	Productive Capacity 1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			(Thousands of Cubic Metres Per Day)								
Light Crude Oil												
Northwest Territories	39.900	4.681	35.219	2.9	4.2	4.2	4.2	4.2	4.2	4.2	3.5	2.1
British Columbia	79.312	60.755	18.557	5.4	5.2	4.8	4.2	3.7	3.2	1.8	1.0	0.5
Alberta	1859.830	1344.895	514.935	143.8	136.6	123.0	107.6	93.6	81.4	43.1	24.5	13.6
Saskatchewan	143.092	109.241	33.851	10.3	10.5	9.5	8.3	7.3	6.4	3.4	1.5	0.7
Manitoba	32.576	22.998	9.578	2.1	2.0	1.9	1.8	1.6	1.5	1.0	0.6	0.4
Ontario	10.102	9.340	0.762	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.0	0.0
Subtotal	2164.812	1551.910	612.902	164.7	158.8	143.6	126.2	110.5	96.9	53.6	31.2	17.4
Heavy Crude Oil												
Alberta	125.732	74.258	51.474	18.1	17.8	15.7	13.6	11.7	10.1	4.8	1.7	0.6
Saskatchewan	278.134	201.902	76.232	21.3	20.5	18.4	16.5	14.7	13.2	7.6	4.0	2.0
Manitoba	0.242	0.207	0.035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	404.108	276.367	127.741	39.4	38.3	34.2	30.0	26.4	23.3	12.5	5.7	2.5
Total Crude Oil												
Northwest Territories	39.900	4.681	35.219	2.9	4.2	4.2	4.2	4.2	4.2	4.2	3.5	2.1
British Columbia	79.312	60.755	18.557	5.4	5.2	4.8	4.2	3.7	3.2	1.8	1.0	0.5
Alberta	1985.562	1419.153	566.409	161.8	154.4	138.7	121.2	105.3	91.5	48.0	26.2	14.2
Saskatchewan	421.226	311.143	110.083	31.6	31.0	27.9	24.8	22.0	19.6	11.1	5.5	2.6
Manitoba	32.818	23.205	9.613	2.1	2.1	1.9	1.8	1.6	1.5	1.0	0.6	0.4
Ontario	10.102	9.340	0.762	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.0	0.0
Total	2568.920	1828.277	740.643	204.1	197.1	177.8	156.3	137.0	120.2	66.1	36.9	19.9

Note: The reserves estimates given in this table are representative of both the high and low price cases. The productive capacity estimates are for the high price case. For the low price case the supply of light crude oil from currently established reserves is projected to be about two percent lower than that in the high price case and the supply of heavy crude oil about five percent lower.

Light Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			(Cubic Metres per Day)								
			Northwest Teritories									
Norman Wells	39.900	4.681	35.219	2860	4200	4200	4200	4200	4200	4200	3533	2143
Pipeline Total	39.900	4.681	35.219	2860	4200	4200	4200	4200	4200	4200	3533	2143
NWT Total	39.900	4.681	35.219	2860	4200	4200	4200	4200	4200	4200	3533	2143
			British Columbia									
			Blueberry Taylor Pipelines									
Aitken Creek-Gething A	1.000	0.939	0.061	37	32	27	23	20	17	0	0	0
Blueberry Debolt	2.642	2.068	0.574	125	147	158	152	135	119	63	34	0
Eagle West Belloy A(80%)	4.160	2.074	2.086	895	886	794	641	517	417	143	49	0
Eagle Belloy B (80%)	0.857	0.291	0.566	180	206	179	153	130	111	49	22	10
Inga-Inga Total	6.250	5.181	1.069	332	298	268	241	217	195	115	67	20
Stoddart West Total	1.057	0.363	0.694	210	210	199	175	153	134	70	36	3
Miscellaneous	0.618	0.297	0.321	35	33	31	29	27	25	20	16	13
Pipeline Total	16.584	11.213	5.371	1816	1814	1658	1416	1201	1021	462	226	47
			Trans-Prairie Pipeline Ltd Beaton-R									
Beatton R. Halfway Tot	1.650	1.370	0.280	102	90	80	71	63	55	30	13	0
Beatton Rvr W. Bluesky A	0.975	0.711	0.264	76	68	61	55	50	45	27	16	9
Eagle West Belloy A(20%)	1.040	0.518	0.522	223	221	198	160	129	104	35	12	0
Eagle Belloy B (20%)	0.214	0.073	0.141	45	51	44	38	32	27	12	5	2
Milligan Creek-Halfway	6.933	6.503	0.430	214	204	176	137	107	83	24	0	0
Peejay-Halfway	10.000	9.019	0.981	336	310	279	245	214	188	97	50	0
Weasel-Halfway	3.150	2.637	0.513	237	215	185	151	123	100	36	13	0
Wildmint-Halfway	1.615	1.379	0.236	105	89	75	63	53	45	19	8	0
Miscellaneous	1.930	1.551	0.379	119	109	99	91	83	76	48	6	0
Pipeline Total	27.507	23.761	3.746	1462	1361	1202	1014	858	728	332	127	12
			Trans-Prairie Pipes Ltd B-Lake Taylor									
Boundary Lake Unit No 1	17.500	12.429	5.071	1060	983	913	847	786	730	503	346	238
Boundary Lake Unit No 2	11.300	9.297	2.003	571	517	468	424	383	347	211	128	78
Bdry Lk Dome 1 & 2	3.300	2.656	0.644	148	136	126	116	107	99	66	44	29
Transprairie Bndlk Misc	0.499	0.343	0.156	43	45	45	42	37	33	18	6	0
Pipeline Total	32.599	24.725	7.874	1822	1682	1552	1430	1316	1210	799	526	347

Table A6-3 (Continued)
Established Reserves and Productive Capacity of Conventional Crude Oil by Pool, Pipeline and Region

Light Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity (Cubic Metres per Day)								
			British Columbia Trucked Oil									
B.C. Trucked Oil	2.622	1.056	1.566	315	350	348	324	294	267	163	100	61
Pipeline Total	2.622	1.056	1.566	315	350	348	324	294	267	163	100	61
B.C. Total	79.312	60.755	18.557	5417	5208	4762	4186	3670	3228	1758	980	468
			Alberta									
			Bow River Pipelines Ltd. Light & Med									
Cessford Banff B	0.579	0.122	0.457	87	82	77	72	68	64	47	35	25
Provost Viking Cak	10.100	6.954	3.146	686	641	599	559	523	488	348	248	176
Miscellaneous & Undef	4.215	1.026	3.189	640	638	606	564	525	488	341	238	166
Pipeline Total	14.894	8.102	6.792	1413	1362	1283	1197	1117	1042	736	521	368
			Cremona Pipeline									
Crossfield Cardium A	3.030	2.811	0.219	85	77	69	62	56	51	30	0	0
Crossfield Field Other	0.877	0.352	0.525	140	137	125	113	102	93	56	34	20
Crossfield East Fld Total	0.993	0.765	0.228	94	84	75	67	60	54	23	0	0
Garrington Card A&B(27%)	0.872	0.708	0.164	50	49	45	40	36	33	20	6	0
Garrington Mann D (27%)	0.085	0.025	0.060	32	27	22	18	14	11	4	0	0
Garrington Viking A(27%)	0.269	0.092	0.177	61	54	48	43	39	34	19	11	0
Garrington Wabamun A	1.230	1.041	0.189	65	72	61	52	44	37	16	7	0
Garrington Fld Other(27%)	0.393	0.208	0.185	54	57	54	48	43	39	22	0	0
Harmattan East Rundle	11.650	10.063	1.587	691	585	496	420	356	302	131	57	0
Harmattan East Viking E	1.070	0.215	0.855	430	384	316	256	207	168	58	0	0
Harmattan Elkton Rundle C	11.500	8.684	2.816	965	847	744	653	573	503	262	136	71
Westward Ho Rundle A	2.200	1.619	0.581	180	180	168	148	130	114	59	31	0
Lochend Cardium A	0.904	0.200	0.704	195	191	175	158	143	129	78	47	4
Miscellaneous & Undef	0.407	0.165	0.242	85	85	85	84	80	72	0	0	0
Pipeline Total	35.480	26.948	8.532	3129	2835	2490	2170	1890	1646	785	332	96
			Federated Pipe Lines Ltd									
Carson Creek North BHL A	6.955	5.235	1.720	1100	950	704	521	386	286	63	1	0
Carson Creek North BHL B	17.000	14.721	2.279	1056	852	768	638	530	441	174	69	0
Judy Creek BHL A	48.000	43.409	4.591	1749	1537	1350	1186	1042	916	479	231	0
Judy Creek BHL B	17.000	14.517	2.483	740	740	738	677	595	522	272	142	0
Judy Creek Viking A	0.860	0.589	0.271	137	115	96	81	68	57	23	0	0

Light Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	Productive Capacity 1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			(Cubic Metres per Day)								
Federated Pipe Lines Ltd												
Meekwap D-2A	4.500	2.637	1.863	700	729	620	518	433	361	147	59	24
Swan Hills BHL A&B	107.500	81.137	26.363	5850	6022	5514	5039	4605	4209	2683	1711	1091
Swan Hills BHL C	25.600	17.345	8.255	1450	1416	1333	1254	1180	1110	818	603	444
Swan Hills South BHL A&B	70.830	50.273	20.557	3575	3600	3525	3115	2750	2459	1591	1165	913
Virginia Hills BHL	21.450	18.981	2.469	1320	1237	974	764	600	471	140	0	0
Virginia Hills Belloy A	4.328	1.086	3.242	1053	930	822	726	641	567	305	164	88
Miscellaneous & Undef	1.190	0.711	0.479	165	138	124	110	97	86	47	26	14
Pipeline Total	325.213	250.641	74.572	18896	18271	16573	14636	12933	11490	6750	4175	2577
Gibson Petroleum Company Ltd.												
Bellshill Blairmore	12.000	7.043	4.957	1900	1966	1691	1413	1180	985	400	162	0
Thompson Lake Blairmore	0.794	0.625	0.169	93	81	65	52	42	34	11	0	0
Miscellaneous & Undef	0.180	0.044	0.136	45	44	41	37	33	30	18	0	0
Pipeline Total	12.974	7.712	5.262	2038	2093	1798	1503	1256	1050	430	162	0
Gulf Canada Pipe Line												
Bashaw Field Total	1.100	0.494	0.606	157	170	153	137	122	110	63	36	21
Chigwell Field Total	1.800	0.748	1.052	345	363	325	287	253	223	119	0	0
Clive D-2A	3.250	2.007	1.243	325	312	283	257	234	212	131	81	50
Clive D-3A	7.030	4.643	2.387	643	583	529	479	435	394	242	148	91
Drumheller D-2A	1.820	1.285	0.535	179	158	140	124	109	96	52	28	15
Drumheller D-2B	2.550	1.417	1.133	605	542	426	335	263	207	62	18	0
Duhamel D-3B	1.460	1.210	0.250	120	114	92	75	60	49	17	0	0
Erskine D-3	3.800	3.434	0.366	125	136	120	105	92	81	42	0	0
Fenn-Big Valley D-2A	53.500	42.417	11.083	6269	5008	4000	3195	2553	2039	663	215	0
Fenn Big Valley D-3F	2.200	1.868	0.332	170	107	94	82	71	62	30	15	0
Fenn West D-2A	1.560	1.135	0.425	183	186	153	126	103	84	31	8	0
Fenn West D-3E	0.796	0.159	0.637	235	235	230	193	158	130	47	17	6
Fenn West Field Other	0.550	0.210	0.340	125	127	111	94	80	68	30	13	0
Hussar Glauconite A	3.400	2.750	0.650	277	237	202	173	148	126	57	26	0
Hussar Field Other	0.930	0.681	0.249	95	85	77	69	63	56	34	0	0
Joffre D-2	8.600	6.542	2.058	465	490	450	412	376	344	219	139	89
Mikwan Field Total	0.643	0.162	0.481	120	119	112	101	91	83	50	30	18
Parflesh L. Mann. C	0.640	0.360	0.280	90	86	76	67	59	51	27	14	7
Rich D-3	1.900	0.472	1.428	250	250	250	250	250	249	157	95	57
Stettler D-2A	4.200	3.875	0.325	122	108	96	86	76	68	37	0	0
Stettler D-3A	3.690	3.024	0.666	290	274	230	192	160	134	54	0	0

Table A6-3 (Continued)
Established Reserves and Productive Capacity of Conventional Crude Oil by Pool, Pipeline and Region

Light Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			(Cubic Metres per Day)								
Gulf Canada Pipe Line												
Wayne-Rosedale Bsl Qtz B	0.908	0.412	0.496	145	143	130	116	104	93	54	31	0
Wayne-Rosedale Fld Other	0.597	0.172	0.425	95	95	95	91	84	78	52	35	0
West Drumheller D-2A	4.800	4.257	0.543	207	183	162	144	127	113	61	0	0
Wood River D-2C	0.518	0.284	0.234	71	63	57	51	45	41	23	13	8
Wood River Field Other	0.891	0.198	0.693	135	135	134	128	118	109	73	49	32
Miscellaneous & Undef	23.688	17.881	5.807	1575	1450	1431	1311	1186	1073	651	395	187
Pipeline Total	136.821	102.097	34.724	13421	11770	10171	8692	7434	6386	3091	1415	586
Imperial Pipe Line Co Ltd Ellerslie												
Acheson D-3A	20.450	16.262	4.188	1900	1795	1468	1199	980	800	291	106	0
Acheson Field Other	1.105	0.787	0.318	130	121	104	90	77	66	31	0	0
Acheson East Blairmore B	0.750	0.343	0.407	210	197	158	126	101	81	27	0	0
Golden Spike D-3A	28.500	27.619	0.881	259	225	199	178	161	146	101	76	0
Morinville D-3B	1.959	1.355	0.604	350	397	307	206	138	92	12	0	0
Yekau Lake D-3A	0.750	0.607	0.143	90	79	59	44	33	25	6	0	0
Miscellaneous & Undef	6.642	5.488	1.154	423	365	316	275	240	211	114	66	0
Pipeline Total	60.156	52.461	7.695	3363	3182	2614	2121	1733	1425	584	249	0
Imperial Pipe Line Co Ltd Excelsior												
Excelsior D-2	4.400	4.104	0.296	128	108	92	78	67	58	30	0	0
Fairydell-Bon Accord D3A	2.070	1.714	0.356	150	132	113	96	82	70	31	14	0
Miscellaneous & Undef	1.042	0.737	0.305	90	98	88	78	69	61	33	18	0
Pipeline Total	7.512	6.555	0.957	368	339	293	253	219	190	95	32	0
Imperial Pipe Line Co Ltd Leduc												
Leduc Woodbend D-2A	14.125	14.015	0.110	65	60	55	47	40	32	0	0	0
Leduc Woodbend D-3A	39.300	38.244	1.056	726	604	475	374	294	231	0	0	0
Miscellaneous & Undef	6.740	6.480	0.260	127	122	99	81	65	53	19	0	0
Pipeline Total	60.165	58.739	1.426	919	787	630	502	400	318	19	0	0
Imperial Pipeline Redwater												
Redwater D-3	128.000	121.350	6.650	2874	2458	2037	1702	1433	1215	582	313	0
Redwater UML Viking A	0.257	0.118	0.139	72	60	50	41	35	29	8	0	0
Miscellaneous & Undef	0.607	0.239	0.368	105	100	96	86	78	70	41	24	0
Pipeline Total	128.864	121.707	7.157	3051	2619	2183	1831	1547	1316	633	338	0

Light Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity (Cubic Metres per Day)								
			Murphy Milk River Pipeline									
Coutts Total	0.600	0.456	0.144	60	64	56	45	37	30	11	0	0
Manyberries Total	2.200	0.691	1.509	520	548	471	405	348	299	140	66	0
Turin Field Total	0.888	0.225	0.663	280	259	221	188	160	136	61	0	0
Miscellaneous & Undef	1.060	0.868	0.192	84	74	66	58	51	45	9	0	0
Pipeline Total	4.748	2.240	2.508	944	947	814	698	598	513	223	66	0
			Norcen Energy Resources Ltd.									
Joarcam Viking	17.440	14.973	2.467	950	900	776	668	575	495	233	110	0
Pipeline Total	17.440	14.973	2.467	950	900	776	668	575	495	233	110	0
			Peace River Oil Pipe Line Co. Ltd									
Ante Creek BHL	2.550	1.683	0.867	245	280	279	255	220	189	89	37	0
Ante Creek BHL B	0.600	0.347	0.253	174	131	99	74	56	42	10	0	0
Bonanza Boundary A	0.505	0.204	0.301	158	131	108	89	74	61	23	0	0
Cherhill Field Total	2.350	1.387	0.963	315	305	270	237	208	183	95	49	13
Edson Field Total	1.572	0.841	0.731	202	187	174	161	149	139	95	65	0
Fox Creek BHL A	0.375	0.178	0.197	95	79	65	54	45	37	14	5	0
Gift Slave Pt A+C+E+F	1.400	0.110	1.290	250	250	246	229	212	195	131	87	58
Gift Field Other	0.586	0.033	0.553	152	137	124	112	101	92	55	33	20
Goose River BHL A	7.160	5.276	1.884	812	739	617	515	430	359	146	59	7
Grand Prairie Halfway A	0.480	0.055	0.425	100	92	84	77	71	65	42	27	18
Kakwa A Cardium A	0.851	0.137	0.714	285	295	251	207	170	140	52	19	0
Kaybob BHL A	16.775	14.717	2.058	1102	912	755	624	517	427	166	0	0
Kaybob South Triassic A	17.600	10.178	7.422	2000	2100	2080	1874	1645	1445	754	393	205
Nipisi Gilwood A(40%)	21.200	13.956	7.244	2240	2400	2398	2160	1804	1507	612	249	101
Nipisi Keg Rvr Sd A(40%)	0.300	0.148	0.152	54	54	46	40	34	29	14	6	0
Nipisi Keg Rvr Sd E(40%)	0.227	0.092	0.135	48	46	41	35	30	26	12	5	0
Nipisi Field Other (40%)	0.598	0.238	0.360	75	96	87	78	71	64	39	23	14
Otter Field Total	1.200	0.090	1.110	250	300	288	258	230	205	115	64	36
Loon Field Total	0.785	0.227	0.558	130	152	137	124	112	102	61	37	22
Panny Keg River D	0.650	0.038	0.612	188	167	149	132	118	105	58	32	18
Panny Field Other	0.759	0.026	0.733	185	180	163	147	132	119	70	41	24
Pine Creek Field Total	0.880	0.505	0.375	121	107	95	85	77	70	45	31	0
Pouce Coupe S. Bdry B	1.200	0.142	1.058	131	163	180	180	180	180	126	84	56
Red Earth Granite Wash A	4.000	2.745	1.255	325	318	291	265	241	219	136	84	52
Red Earth Slave Pt A	0.799	0.433	0.366	125	118	104	92	81	71	38	20	0
Red Earth Field Other	3.886	1.669	2.217	350	380	367	334	305	280	193	142	110

Table A6-3 (Continued)
Established Reserves and Productive Capacity of Conventional Crude Oil by Pool, Pipeline and Region

Light Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity (Cubic Metres per Day)								
Peace River Oil Pipe Line Co. Ltd												
Rycroft Field Total	0.670	0.070	0.600	120	170	168	153	135	119	63	34	18
Simonette D-3	6.100	5.472	0.628	276	234	198	168	142	121	53	23	0
Snipe Lake BHL	10.000	7.734	2.266	570	572	524	474	429	388	235	143	86
Spirit River Doig A	0.850	0.094	0.756	227	203	181	162	145	130	74	42	24
Sturgeon Lake D-3	3.690	3.159	0.531	170	151	135	121	108	96	54	31	17
Sturgeon Lake South D-3	25.500	18.425	7.075	2000	2195	2011	1757	1535	1341	683	347	177
Sturgeon Lake South D-3C	0.450	0.070	0.380	110	110	104	92	80	70	37	19	10
Tangent Field Total	1.860	0.169	1.691	340	400	381	345	312	282	171	104	63
Utikuma Lk KR Sand A(16%)	1.224	0.682	0.542	182	193	171	146	124	106	47	21	9
Utik. Lk KR Sd NKRAA(16%)	0.211	0.096	0.115	54	56	45	35	28	22	6	1	0
Utikuma Lk Fld Other(16%)	0.436	0.083	0.353	80	80	79	73	66	59	36	22	13
Valhalla Doe Creek I	2.540	0.272	2.268	560	560	531	480	433	391	235	141	84
Valhalla Field Other	0.950	0.086	0.864	205	229	207	187	170	153	93	56	34
Wembley Halfway B	2.400	0.407	1.993	430	534	496	445	398	357	206	118	68
Wembley Field Other	0.457	0.076	0.381	95	140	131	112	97	83	39	0	0
Windfall D-3A	2.800	2.042	0.758	265	190	171	154	138	124	73	43	25
Miscellaneous &Undef	6.766	4.099	2.667	700	784	711	640	576	519	307	181	0
Pipeline Total	156.192	98.491	57.701	16503	16934	15765	14003	12249	10731	5623	2941	1396
Pembina Pipeline Company Ltd												
Bigoray Cardium B	0.800	0.247	0.553	183	155	132	114	98	86	46	27	17
Bigoray Nisku B	0.900	0.325	0.575	160	160	156	138	121	106	55	29	15
Bigoray Nisku E	0.900	0.252	0.648	180	180	178	160	140	123	64	33	17
Bigoray Nisku F	1.510	0.702	0.808	380	387	324	252	196	153	43	12	0
Bigoray Nisku H	0.750	0.188	0.562	220	217	188	157	131	110	44	18	0
Bigoray Nisku K	0.340	0.153	0.187	79	63	52	43	37	32	18	11	0
Brazeau River Nisku A	3.975	1.766	2.209	1085	1084	931	711	543	414	107	27	0
Brazeau River Nisku B	1.840	0.472	1.368	435	460	460	431	356	293	110	41	34
Brazeau River Nisku D	1.760	0.542	1.218	375	400	400	369	308	258	104	42	17
Brazeau River Nisku E	1.500	0.648	0.852	435	434	370	280	211	160	39	0	0
Brazeau River Fld Other	1.584	0.376	1.208	240	300	287	260	235	212	129	78	47
Carrot Creek Field Total	2.277	0.434	1.843	550	559	521	457	402	353	184	96	50
Crystal Viking A	5.749	0.489	5.260	1060	1100	1100	1086	995	901	546	331	201
Cyn-Pem Cardium A	2.230	1.883	0.347	180	136	106	85	70	58	28	17	0
Cyn-Pem Cardium D	0.355	0.115	0.240	118	99	82	68	57	47	19	0	0
Cyn-Pem Field Other	1.335	0.301	1.034	300	298	271	240	213	189	103	57	31
Highvale Lower Mann A	0.625	0.175	0.450	122	120	106	92	82	73	45	31	23
Highvale Field Other	0.920	0.213	0.707	150	190	171	155	140	126	76	45	27

Light Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	Productive Capacity 1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			(Cubic Metres per Day)								
Pembina Pipeline Company Ltd												
Minnehik Buck Lk Fld Total	0.733	0.171	0.562	170	152	137	124	112	103	69	49	0
Niton Basal Quartz B	1.520	0.896	0.624	150	145	131	120	109	100	66	45	32
Pembina Cardium	228.000	157.233	70.767	7350	6990	6734	6391	6074	5779	4585	3726	3088
Pembina Keystone BR B	8.000	5.674	2.326	551	498	451	410	373	340	218	145	100
Pembina Keystone BR C	2.782	1.884	0.898	305	270	239	212	187	166	90	49	26
Pembina Keystone BR I	1.633	0.899	0.734	120	119	115	108	101	96	73	57	46
Pembina Keystone BR M	1.470	0.956	0.514	106	99	93	87	82	77	56	40	29
Pembina Keystone BR U	1.800	0.963	0.837	180	180	176	163	151	139	93	62	42
Pembina Keystone BR X	1.316	0.384	0.932	130	130	130	129	122	114	84	64	51
Pembina Belly Rvr Other	3.472	1.276	2.196	440	440	437	409	377	348	233	156	105
Pembina Nisku A	1.960	0.639	1.321	462	500	498	430	345	277	92	30	10
Pembina Nisku C	0.715	0.353	0.362	200	177	139	110	86	68	20	0	0
Pembina Nisku D	2.550	1.093	1.457	700	699	602	464	358	276	75	20	0
Pembina Nisku G	2.100	0.648	1.452	620	585	486	402	333	275	106	41	15
Pembina Nisku J	0.564	0.196	0.368	110	89	81	73	66	60	36	22	13
Pembina Nisku K	1.700	0.518	1.182	500	467	389	323	268	223	88	35	13
Pembina Nisku L	4.100	0.784	3.316	1000	1000	1000	1000	933	766	281	103	38
Pembina Nisku M	2.140	0.458	1.682	633	630	559	467	390	325	132	53	21
Pembina Nisku O	1.190	0.182	1.008	290	290	290	281	242	206	92	41	18
Pembina Nisku P	3.190	0.457	2.733	800	900	859	736	627	534	240	107	48
Pembina Nisku Q	2.350	0.060	2.290	385	320	301	261	230	205	130	94	73
Pembina Nisku S	0.350	0.084	0.266	100	100	91	76	63	53	21	8	0
Pembina Nisku Misc.	2.922	1.075	1.847	510	509	471	417	370	328	180	98	54
Pembina Ostracod E	1.000	0.167	0.833	130	200	199	185	168	152	92	55	33
Westpem Nisku A	1.990	0.632	1.358	588	546	452	374	309	256	99	38	14
Westpem Nisku C	3.200	0.771	2.429	850	850	817	690	576	481	195	79	32
Westpem Nisku D	1.540	0.517	1.023	450	414	342	283	234	193	74	28	11
Will-Green Card A (75%)	20.250	11.603	8.647	1012	941	879	823	773	728	557	444	365
Will-Green Viking A(75%)	0.412	0.269	0.143	60	56	48	42	36	32	16	0	0
Will-Green Fld Other(75%)	1.108	0.423	0.685	172	190	172	156	141	127	77	47	0
Pembina Pipeline Misc&Und	3.890	1.640	2.250	650	669	597	532	474	422	237	133	41
Pipeline Total	339.297	202.186	137.111	25982	25512	23774	21401	19070	16964	10192	6789	4794
Rainbow Pipeline Company Limited												
Amigo Field Total	0.622	0.166	0.456	130	129	117	104	92	82	45	24	13
Amber Field Total	1.000	0.284	0.716	200	212	189	167	148	132	72	39	21
Evi Field Total	1.800	0.461	1.339	319	283	252	226	204	185	121	85	63
Golden-Slave Pt A	2.500	1.678	0.822	380	345	283	233	191	157	58	21	0

Table A6-3 (Continued)
Established Reserves and Productive Capacity of Conventional Crude Oil by Pool, Pipeline and Region

Light Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity (Cubic Metres per Day)								
				Rainbow Pipeline Company Limited								
Mitsue-Gilwood A	61.000	38.739	22.261	4175	4193	4325	4400	4283	3890	2359	1431	868
Nipisi Gilwood A (60%)	31.800	20.933	10.867	3360	3600	3597	3241	2707	2261	919	373	151
Nipisi Keg Rvr Sd A(60%)	0.450	0.222	0.228	81	81	69	60	51	44	21	9	0
Nipisi Keg Rvr Sd E(60%)	0.341	0.138	0.203	72	70	62	53	46	39	18	8	0
Nipisi Field Other (60%)	0.897	0.357	0.540	112	144	130	118	106	96	58	35	21
Rainbow KR A	11.298	8.173	3.125	1103	964	842	736	643	562	286	145	74
Rainbow KR B	30.470	17.725	12.745	1525	1572	1392	1226	1092	983	645	472	368
Is No. 1 Other	11.126	8.936	2.190	924	787	671	571	487	415	186	83	4
Rainbow KR F	19.100	13.986	5.114	1602	1421	1261	1119	993	881	484	266	146
Rainbow KR I	3.410	2.309	1.101	330	358	313	272	236	205	102	50	25
Rainbow KR N	0.900	0.543	0.357	180	162	130	104	83	67	22	7	0
Rainbow KR Aa	7.000	6.311	0.689	242	269	233	196	166	140	59	25	0
Rainbow KR Ii	2.251	1.643	0.608	120	140	138	123	107	94	55	36	25
Rainbow KR Mm	0.500	0.150	0.350	120	119	111	95	82	70	33	15	0
I.S. No. 2 Other	4.287	3.038	1.249	551	463	390	328	276	232	98	41	17
I.S. No. 11 Other	3.258	2.610	0.648	286	242	206	175	148	126	55	24	0
Rainbow Field Other	8.898	5.635	3.263	1425	1384	1144	945	780	645	248	95	0
Rainbow South-KR A	1.750	1.624	0.126	62	56	47	39	32	27	9	0	0
Rainbow South-KR B	4.200	3.099	1.101	350	320	320	320	294	246	100	40	16
Rainbow South-KR E	2.570	2.101	0.469	145	120	113	101	90	81	46	26	15
Rainbow S. Fld Other	3.275	1.895	1.380	469	413	364	320	282	248	131	69	37
Sawn Lake Slave Pt A	0.485	0.040	0.445	110	108	99	89	81	73	44	26	16
Sawn Lake Slave Pt J	0.700	0.018	0.682	120	140	140	139	132	119	72	43	26
Seal Slave Pt A	0.560	0.223	0.337	113	100	89	79	70	62	34	18	9
Shekilie Field Total	3.218	1.490	1.728	800	739	606	496	406	332	122	45	0
Slave-Slave Pt G+L	0.950	0.178	0.772	201	250	241	209	180	155	73	34	16
Slave-Slave Pt. H	1.000	0.076	0.924	400	447	379	295	230	179	51	14	0
Utikuma Lk KR Sand A(84%)	6.426	3.583	2.843	958	1015	898	765	652	556	249	112	50
Utik. Lk KR Sd NKRAA(84%)	1.110	0.503	0.607	283	297	243	191	150	118	35	0	0
Utikuma Lk Fld Other(84%)	2.287	0.434	1.853	420	420	418	388	351	317	192	116	70
Virgo Field Total	7.147	5.615	1.532	532	651	570	469	385	317	119	45	0
Zama Field Total	14.908	10.680	4.228	1150	1149	1081	978	885	801	485	294	0
Miscellaneous & Undef	1.442	1.335	0.107	55	46	39	33	27	23	5	0	0
Pipeline Total	254.936	166.931	88.005	23410	23225	21515	19418	17188	14976	7729	4187	2061
				Rangeland Pipeline Company Limited								
Caroline Cardium E	2.200	0.782	1.418	400	400	395	355	312	274	143	74	39
Caroline Viking A	1.241	0.778	0.463	120	111	103	96	89	82	56	39	0

Light Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity (Cubic Metres per Day)								
Rangeland Pipeline Company Limited												
Ferrier Cardium D	3.000	1.498	1.502	258	238	220	204	190	177	128	97	76
Ferrier Cardium E	4.850	2.126	2.724	440	439	407	359	321	289	192	141	111
Ferrier Cardium G	3.494	0.738	2.756	380	400	399	377	343	315	217	162	127
Garrington Card A&B(73%)	2.358	1.915	0.443	135	131	119	107	97	87	52	31	0
Garrington Mann D (73%)	0.230	0.067	0.163	87	74	60	48	39	31	10	0	0
Garrington Viking A(73%)	0.728	0.248	0.480	165	147	132	118	105	94	53	30	0
Garrington Fld Other(73%)	1.062	0.565	0.497	146	152	144	129	116	104	60	5	0
Gilby Basal Mann. B	1.300	0.900	0.400	86	80	75	69	64	60	41	29	20
Gilby Jurassic B	3.670	2.354	1.316	277	253	232	212	195	179	120	83	59
Gilby Field Other	4.434	3.531	0.903	230	239	225	199	177	157	91	56	35
Innisfail D-3	12.500	10.741	1.759	925	904	710	548	422	325	88	0	0
Med River Glauconitic A	2.110	1.405	0.705	275	277	243	205	173	146	62	0	0
Med River Jurassic A	1.800	1.571	0.229	118	97	81	67	55	45	17	0	0
Med River Jurassic C&K	2.170	1.357	0.813	235	226	202	181	162	145	84	48	28
Med River Jurassic D	2.130	1.451	0.679	167	153	140	128	117	107	68	44	28
Med River Pekisko E	0.791	0.466	0.325	56	50	45	41	37	34	24	18	14
Med River Pekisko I	1.100	0.733	0.367	185	181	145	114	89	70	21	0	0
Med River Pekisko N	0.600	0.172	0.428	75	72	68	62	57	53	37	28	21
Med River Viking D&F	0.560	0.147	0.413	250	227	176	135	104	80	0	0	0
Med River Field Other	2.453	1.563	0.890	265	265	253	224	199	176	97	53	0
Ricinus Cardium A	2.880	1.100	1.780	345	310	304	277	252	230	151	105	76
Ricinus Field Other	2.912	1.354	1.558	400	400	379	339	304	272	157	90	52
Sundre Rundle A	5.600	4.606	0.994	390	371	332	280	235	198	84	35	0
Sylvan Lake Pekisko B	2.300	1.416	0.884	230	222	201	182	165	149	90	54	33
Sylvan Lake Field Other	3.705	2.030	1.675	410	410	403	367	332	301	182	110	67
Will-Green Card A(25%)	6.750	3.868	2.882	337	313	293	274	257	242	185	148	121
Will-Green Viking A(25%)	0.138	0.090	0.048	20	19	17	15	13	11	1	0	0
Will-Green Fld Other(25%)	0.369	0.141	0.228	57	63	57	51	47	42	25	15	0
Wimborne D-3A	3.200	2.318	0.882	407	400	362	282	220	171	49	14	0
Miscellaneous & Undef	4.180	2.342	1.838	537	458	414	375	339	307	186	113	68
Pipeline Total	86.815	54.373	32.442	8415	8096	7349	6436	5642	4970	2787	1632	981
Texaco Canada Inc.												
Bonnie Glen D-3A	86.500	72.215	14.285	9107	7531	5911	4385	3253	2413	542	73	0
Glen Park D-3A	3.424	2.967	0.457	267	211	166	131	104	82	25	7	0
Westerose D-3	22.000	17.283	4.717	3250	2592	1904	1399	1027	755	161	33	0
Wizard Lake D-3A	59.000	46.777	12.223	4830	4120	3883	3284	2770	2337	999	427	182
Miscellaneous & Undef	1.945	1.594	0.351	97	104	95	84	74	66	36	20	10
Pipeline Total	172.869	140.836	32.033	17552	14559	11962	9285	7230	5654	1764	561	193

Table A6-3 (Continued)
Established Reserves and Productive Capacity of Conventional Crude Oil by Pool, Pipeline and Region

Light Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			(Cubic Metres per Day)								
			Trans-Prairie Ltd. Boundary Lake S .									
Boundary L. South Tria. C	0.640	0.326	0.314	55	49	45	41	38	35	26	20	17
Boundary L. South Tria. E	4.070	2.231	1.839	422	388	358	329	303	279	185	122	81
Boundary L. South Tria. H	0.649	0.166	0.483	80	80	79	74	70	66	48	35	26
Miscellaneous & Undef	0.420	0.051	0.369	135	109	99	88	78	69	38	20	0
Pipeline Total	5.779	2.774	3.005	692	628	582	535	491	451	298	200	124
			Twining Pipeline Division									
Twining-Rundle A & Lm A	5.600	2.593	3.007	462	429	400	374	351	331	254	205	170
Twining North Rundle	1.900	1.000	0.900	236	211	190	171	155	142	94	66	49
Miscellaneous & Undef	0.550	0.238	0.312	101	100	88	78	68	60	31	16	0
Pipeline Total	8.050	3.831	4.219	799	741	679	624	576	533	380	288	219
			Valley Pipeline									
Turner Valley Total	25.485	21.605	3.880	460	459	447	426	407	389	316	261	219
Pipeline Total	25.485	21.605	3.880	460	459	447	426	407	389	316	261	219
			Truck And Tank Light									
Truck & Tank Light	0.740	0.333	0.407	120	100	98	90	81	73	44	27	16
Pipeline Total	0.740	0.333	0.407	120	100	98	90	81	73	44	27	16
			Light Undefined & Confidential									
Light Undef & Confid	5.400	1.360	4.040	1325	1250	1220	1073	931	809	399	197	0
Pipeline Total	5.400	1.360	4.040	1325	1250	1220	1073	931	809	399	197	0
Alberta Total	1859.830	1344.895	514.935	143756	136613	123024	107569	93577	81428	43122	24491	13637
			Saskatchewan									
			Bow River Pipeline Ltd - Light									
Avon Hill Viking	0.704	0.348	0.356	126	133	120	109	98	89	19	0	0
Dodsland Eagle L Vol	3.036	1.784	1.252	340	376	343	307	275	246	142	82	0
Dodsland Gleneath Unit	2.654	1.705	0.949	235	242	221	202	185	169	108	68	43
Dodsland Viking Sand Non	6.300	2.514	3.786	1225	1300	1271	1129	992	871	454	0	0
Eureka Viking South Unit	1.380	1.068	0.312	62	58	55	52	49	46	36	29	24

Table A6-3 (Continued)
Established Reserves and Productive Capacity of Conventional Crude Oil by Pool, Pipeline and Region

Light Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity (Cubic Metres per Day)								
Bow River Pipeline Ltd - Light												
Kerrobert Viking	3.179	0.024	3.155	660	1031	905	795	698	613	320	167	87
Miscellaneous Total	2.030	1.564	0.466	212	181	154	131	112	95	52	0	0
Pipeline Total	19.283	9.007	10.276	2861	3323	3073	2728	2411	2132	1133	347	155
Westspur Pipeline Co-S.E. Sask Lht												
Alameda-Midale East Unit	1.879	1.443	0.436	75	72	68	64	61	58	44	34	26
Alida East-Unit	1.992	1.759	0.233	59	54	50	46	42	39	26	17	11
Alida West - Alida Non	2.081	1.734	0.347	88	80	74	68	62	57	37	24	16
Arcola Frobisher-Alida	1.300	0.873	0.427	100	95	88	80	74	68	44	29	19
Browning-Frob Alida Non	1.100	0.788	0.312	76	71	65	60	56	51	35	23	16
Carnduff -Midale E Unit	2.900	2.621	0.279	91	84	78	72	67	62	42	0	0
Elmore - Frob Vol Unit	2.075	1.647	0.428	105	96	88	81	74	68	44	28	18
Flat Lk Ratcliffe Vol Un	2.100	1.451	0.649	162	148	135	124	113	103	66	42	27
Freda Lake Ratcliffe Non	0.964	0.408	0.556	122	138	126	115	105	96	61	39	25
Hastings - Frob Non-Unit	2.020	1.676	0.344	122	120	105	93	81	71	37	0	0
Hastings Frobisher Units	2.840	2.457	0.383	99	92	85	78	72	66	44	30	12
Ingoldsby-Frob Vol Unit	2.500	2.148	0.352	85	78	72	66	61	56	38	26	18
Kenosee-Tilston Vol Unit	2.160	1.787	0.373	145	126	109	95	82	71	35	17	0
Nottingham Field Total	2.718	2.188	0.530	104	98	92	86	81	76	55	40	29
Parkman-Til Souris V Non	4.100	2.920	1.180	395	397	351	308	271	238	124	64	0
Queensdale East-Frob Non	6.217	3.993	2.224	450	470	434	400	369	340	227	151	101
Rosebank-Frob Vol Unit 1	3.700	3.454	0.246	100	92	79	68	58	50	23	0	0
Sherwood-Frobisher Non	1.950	1.614	0.336	86	78	72	65	60	55	35	22	14
Star Valley-Frob Ali Non	1.870	1.132	0.738	227	203	181	162	145	129	74	42	24
Steelman Midale Unit 1A	8.900	8.111	0.789	270	241	214	190	169	151	84	47	0
Steelman Midale Unit 2	8.600	7.564	1.036	258	236	216	198	181	166	107	68	44
Steelman Midale Unit 3	4.470	3.899	0.571	170	163	147	131	118	105	61	35	13
Steelman Midale Unit 4	5.650	4.650	1.000	261	242	221	202	185	169	108	69	44
Steelman Midale Unit 6	9.235	8.628	0.607	223	210	190	166	145	126	64	0	0
Steelman Midale Non-Unit	0.850	0.582	0.268	104	93	84	75	67	60	35	0	0
Steelman Field Other	5.540	5.007	0.533	233	202	176	153	133	116	57	0	0
Viewfield-Frob Alida Non	0.700	0.442	0.258	77	70	63	56	51	46	27	16	9
Willmar-Frob Ali Non-Un	3.350	2.693	0.657	207	203	189	166	146	129	68	36	0
Willmar Frob-Ali Units	2.087	1.685	0.402	91	85	79	73	68	63	43	30	21
Workman-Frob Vol Unit 1	1.820	1.608	0.212	72	68	60	53	47	41	22	12	0
Workman-Frob Non-Unit	1.650	0.990	0.660	155	153	141	130	119	110	72	48	31
Miscellaneous	24.491	18.282	6.209	2600	2594	2287	1872	1533	1255	461	137	0
Pipeline Total	123.809	100.234	23.575	7426	7168	6433	5614	4911	4307	2315	1137	524
Saskatchewan Total	143.092	109.241	33.851	10288	10491	9506	8342	7323	6439	3449	1485	680

Table A6-3 (Continued)
Established Reserves and Productive Capacity of Conventional Crude Oil by Pool, Pipeline and Region

Light Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	Productive Capacity 1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			(Cubic Metres per Day)								
Manitoba												
TransPrairie Pipelines												
Daly Field Total	4.568	3.654	0.914	300	293	263	233	206	183	100	55	0
Virden Field Total	22.400	17.898	4.502	910	852	798	748	701	657	474	342	247
Manitoba Miscellaneous	1.210	0.718	0.492	182	174	152	133	116	101	51	0	0
Pipeline Total	28.178	22.270	5.908	1392	1320	1214	1115	1024	942	626	397	247
Waskada Pipeline												
Waskada Field Total	4.398	0.728	3.670	720	719	691	638	588	543	364	244	163
Pipeline Total	4.398	0.728	3.670	720	719	691	638	588	543	364	244	163
Provincial Total	32.576	22.998	9.578	2112	2040	1905	1753	1613	1486	991	642	411
Ontario												
Provincial Total	10.102	9.340	0.762	245	230	204	181	161	142	78	43	8
Canada Total	2164.812	1551.910	612.902	164678	158783	143601	126230	110543	96923	53600	31176	17350

Heavy Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	1985	1986	1987	1988	1989	1990	1995	2000	2005
Alberta												
Bow River Pipeline Ltd Heavy												
Alderson Field Total	2.722	1.221	1.501	530	576	513	437	373	317	142	0	0
Bantry Mannville A & FF	7.583	5.267	2.316	580	589	558	502	452	407	241	142	84
Bantry Mannville D	1.100	0.715	0.385	110	113	103	91	81	72	39	21	11
Bantry Field Other	0.720	0.363	0.357	145	137	117	100	85	72	32	0	0
Cessford Total Heavy	6.035	4.042	1.993	440	437	410	378	349	322	216	144	97
Chin Coulee Bsl Mann A	0.910	0.746	0.164	79	68	59	51	44	38	0	0	0
Countess U Mann B	1.300	1.032	0.268	168	131	103	80	63	49	14	0	0
Countess U Mann D	6.300	4.378	1.922	780	720	608	513	433	366	157	67	29
Countess U Mann H	2.100	1.812	0.288	165	138	110	87	68	53	16	0	0
Countess U Mann O	1.000	0.576	0.424	158	137	119	103	89	77	38	18	9
Enchant L Mann G	0.285	0.055	0.230	100	92	77	65	54	45	19	3	0
Grand Forks U Mann B	1.350	0.833	0.517	140	122	107	95	84	75	45	30	20

Table A6-3 (Continued)
Established Reserves and Productive Capacity of Conventional Crude Oil by Pool, Pipeline and Region

Heavy Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity (Cubic Metres per Day)								
Bow River Pipeline Ltd Heavy												
Grand Forks L Mann A	1.300	0.484	0.816	320	319	284	235	195	161	63	24	0
Grand Forks L Mann D	5.900	4.071	1.829	816	685	575	483	406	341	142	59	24
Grand Forks L Mann E	1.884	0.829	1.055	460	420	351	292	244	203	82	33	0
Grand Forks L Mann G	1.000	0.480	0.520	221	188	160	136	116	98	44	19	0
Grand Forks L Mann K & V	2.040	1.343	0.697	320	268	225	188	158	132	54	22	0
Grand Forks L Mann II	1.800	0.077	1.723	620	681	579	484	404	337	137	55	22
Grand Forks Field Other	2.848	0.944	1.904	810	906	731	589	475	383	130	0	0
Hays Lower Mann A	1.650	1.345	0.305	112	98	85	75	65	57	29	15	1
Hays Field Other	0.594	0.256	0.338	127	142	118	98	82	68	27	11	0
Horsefly Lake Mannville	1.170	0.909	0.261	101	90	80	71	63	56	32	0	0
Jenner Field Total	1.314	0.925	0.389	155	145	125	107	92	79	37	0	0
Lathom U Mann A	2.350	1.590	0.760	253	223	196	173	152	134	71	37	20
Little Bow Field Total	1.816	0.576	1.240	300	350	375	362	315	271	128	60	0
Sibbald U Mannville C	0.723	0.133	0.590	160	218	194	165	140	120	53	24	0
Suffield Field Total	0.726	0.282	0.444	180	202	168	139	116	96	38	0	0
Taber Mann D	2.300	1.683	0.617	208	185	166	148	132	118	67	38	0
Taber North Glauc A	1.800	0.333	1.467	470	456	399	348	304	266	135	68	35
Taber North Field Other	1.744	0.718	1.026	385	383	343	292	249	212	95	9	0
Taber South Mann A	1.200	0.891	0.309	83	71	63	56	50	45	31	23	18
Taber South Mann B	2.125	1.813	0.312	112	100	88	78	69	61	33	18	0
Turin U Mann C	0.470	0.141	0.329	90	83	72	63	56	50	30	20	14
Turin Field Other	0.565	0.251	0.314	117	121	105	90	77	66	31	0	0
Wrentham Field Total	0.737	0.387	0.350	131	117	103	92	81	72	39	0	0
Miscellaneous & Undef	5.852	3.403	2.449	852	899	829	714	614	529	249	0	0
Pipeline Total	75.313	44.904	30.409	10805	10628	9313	7999	6848	5868	2752	972	390
BP Exploration Canada Limited												
Chauvin Mannville A	1.250	1.052	0.198	66	60	54	49	44	40	24	0	0
Chauvin Field Other	0.408	0.125	0.283	93	89	83	73	65	57	31	12	0
Chauvin South Spky A & B	1.690	1.069	0.621	180	174	157	141	127	114	67	40	9
Chauvin South Spky E	0.900	0.449	0.451	165	161	139	120	104	90	43	21	0
Chauvin South Spky H	0.768	0.451	0.317	128	115	99	84	72	62	28	13	0
Chauvin South Fld Other	1.043	0.555	0.488	190	189	170	146	126	108	51	0	0
David Lloyd A	0.770	0.388	0.382	145	148	130	108	90	75	30	12	0
David Lloyd C	0.395	0.123	0.272	141	116	96	79	65	54	20	0	0
Hayter Dina A 38%	0.376	0.098	0.278	120	114	96	80	67	56	22	0	0
Hayter Dina B 38%	0.260	0.078	0.182	65	80	67	56	47	39	15	0	0
Hayter Field Other 38%	0.229	0.119	0.110	47	48	42	36	30	26	0	0	0
Miscellaneous & Undef	0.043	0.025	0.018	9	7	6	5	4	4	0	0	0
Pipeline Total	8.132	4.532	3.600	1349	1306	1143	984	847	730	338	99	9

Table A6-3 (Continued)
Established Reserves and Productive Capacity of Conventional Crude Oil by Pool, Pipeline and Region

Heavy Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			(Cubic Metres per Day)								
Husky Pipeline & Manito Lloyd												
Hayter Dina A 62%	0.614	0.159	0.455	196	188	159	133	111	92	37	0	0
Hayter Dina B 62%	0.424	0.127	0.297	136	127	106	88	74	61	25	0	0
Hayter Field Other 62%	0.374	0.194	0.180	77	73	70	60	51	44	0	0	0
Lloydminster Sparky B	0.781	0.378	0.403	85	80	75	70	66	62	46	33	24
Lloyd Sparky C & GP A	1.400	1.097	0.303	125	125	108	93	80	69	32	0	0
Lloydminster Sparky G	0.845	0.449	0.396	180	166	140	119	100	85	36	0	0
Lloydminster Sparky K	1.000	0.452	0.548	205	211	183	157	135	117	55	0	0
Lloyd Sparky & GP C&D	3.630	2.594	1.036	235	226	210	195	182	169	117	81	56
Lloydminster Field Other	2.372	1.452	0.920	280	279	262	237	215	194	118	0	0
Morgan Lloyd A	0.600	0.199	0.401	180	167	143	123	105	90	36	0	0
Morgan Sparky A	0.300	0.106	0.194	80	76	66	56	49	42	19	0	0
Vermillion Sparky A	0.651	0.464	0.187	85	79	68	58	50	43	7	0	0
Viking Kinsella Wain B	4.550	3.275	1.275	600	549	459	383	320	267	108	0	0
Wainwright Wain & Spk A	12.500	8.596	3.904	1300	1331	1184	1029	894	778	386	191	0
Wainwright Field Other	0.920	0.166	0.754	260	297	256	220	189	163	77	0	0
Wildmere Lloyd A & Spk E	3.000	1.225	1.775	510	477	429	385	346	311	182	106	62
Miscellaneous & Undef	0.936	0.505	0.431	160	160	157	138	119	102	48	0	0
Pipeline Total	34.897	21.438	13.459	4694	4619	4082	3554	3094	2696	1336	414	144
Truck And Tank - Heavy												
Glenevis Banff	1.630	1.222	0.408	110	101	93	85	78	72	47	30	11
Provost U Mann B	0.550	0.353	0.197	66	57	51	45	41	37	25	0	0
Provost U Mann BB	0.320	0.076	0.244	110	102	87	74	63	54	24	0	0
St. Anne Field Total	0.284	0.035	0.249	80	76	67	59	52	46	24	13	7
Miscellaneous & Undef	3.698	1.547	2.151	647	710	701	620	534	459	217	102	0
Pipeline Total	6.482	3.233	3.249	1014	1048	1000	885	770	669	339	146	19
Heavy Undefined & Confidential												
Heavy Undef & Conf	0.908	0.151	0.757	218	196	176	159	143	128	75	44	26
Pipeline Total	0.908	0.151	0.757	218	196	176	159	143	128	75	44	26
Alberta Total	125.732	74.258	51.474	18082	17799	15717	13582	11703	10095	4842	1678	589
Saskatchewan												
Husky-Manito Pipelines												
Aberfeldy Spky Sd Unit	6.700	4.868	1.832	387	363	341	320	300	281	204	148	108
Aberfeldy S Spky Sd	1.581	1.414	0.167	65	58	51	45	40	36	19	0	0

Heavy Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)						(Cubic Metres per Day)					
							Productive Capacity					
Husky-Manito Pipelines												
Celtic GP Sand Non	1.149	0.094	1.055	255	255	245	222	201	181	110	66	40
Celtic Sparky Sand Non	0.586	0.074	0.512	100	130	123	112	101	91	55	33	20
Celtic Waseca Sand Non	1.563	0.203	1.360	285	330	324	296	268	242	147	89	54
Dee Valley Waseca Non	0.688	0.245	0.443	117	123	111	100	90	81	48	28	16
Dulwich Sparky Sand	1.877	1.634	0.243	60	57	53	50	48	45	36	18	0
Edam West Mannville Sd	0.440	0.047	0.393	105	100	90	81	74	67	40	24	14
Edam West Sparky	0.451	0.042	0.409	110	104	94	85	77	70	42	25	15
Edam West Waseca	0.535	0.052	0.483	102	123	112	101	91	82	50	30	18
Epping Spky & GP Non Unt	2.250	1.869	0.381	155	147	130	116	103	91	26	0	0
Epping South Spky&Gp Unt	2.800	2.420	0.380	119	108	98	89	81	73	45	28	0
Epping Sw Sparky Unit	1.100	0.807	0.293	85	78	71	64	59	53	33	21	0
Golden Lk North Vol Unit	1.900	1.455	0.445	133	121	110	100	91	83	52	32	0
Golden Lk North Non Unit	0.640	0.407	0.233	80	72	65	59	53	48	28	0	0
Golden Lk S Sparky Non	1.400	0.584	0.816	162	200	199	187	169	153	93	56	34
Golden Lk S Waseca Non	2.300	1.418	0.882	295	277	246	218	193	171	94	51	0
Gully Lk Waseca Vol Unit	1.050	0.650	0.400	135	137	122	106	92	80	39	19	0
Gully Lk Waseca Non Unit	1.105	0.620	0.485	185	172	150	130	113	98	49	7	0
Lashburn Field Total	1.715	1.038	0.677	242	243	211	183	159	138	69	12	0
Macklin Sparky Sd Non	0.405	0.297	0.108	67	53	43	35	29	24	0	0	0
Maidstone Mclaren Sand	0.503	0.100	0.403	97	104	97	89	81	73	45	28	16
Marsden S Sparky Non	0.425	0.250	0.175	133	98	73	53	39	29	0	0	0
Neilburg Mclaren Sand	0.795	0.209	0.586	200	188	165	145	127	111	57	30	0
Northminster Field Total	1.177	0.855	0.322	100	96	87	78	70	63	37	22	0
Pikes Peak Waseca Sand	2.600	0.600	2.000	775	755	639	539	455	383	164	70	29
Senlac Lloydminster Sd	1.230	0.280	0.950	266	241	219	198	180	163	100	61	37
Standard Hill Waseca Sd	1.690	0.801	0.889	275	261	234	209	186	166	94	53	0
Tangleflags GP Non	2.375	1.117	1.258	330	342	308	278	251	226	135	80	48
Tangleflags Lloyd Sd Non	1.500	0.690	0.810	220	219	208	189	171	155	95	58	0
Tangleflags N Lloyd Sd	0.550	0.162	0.388	102	106	96	87	79	71	43	26	7
Tangleflags Other	2.235	1.093	1.142	380	379	333	293	257	225	117	61	0
Miscellaneous	12.019	7.498	4.521	1782	1566	1376	1209	1063	934	489	0	0
Pipeline Total	59.334	33.893	25.441	7913	7623	6840	6082	5404	4806	2670	1189	463
Bow River Pipeline Ltd - Heavy												
Cactus Lake Bakken Sand	3.100	0.879	2.221	570	553	507	459	415	375	227	138	83
Coleville Bakken Sand	8.500	6.389	2.111	550	526	481	439	401	366	232	147	93
Court Bakken Sand	0.631	0.085	0.546	170	151	135	120	107	96	54	30	17
N Hoosier Bakken Sd Vol	1.188	0.812	0.376	95	87	79	72	66	60	37	23	15

Table A6-3 (Continued)
Established Reserves and Productive Capacity of Conventional Crude Oil by Pool, Pipeline and Region

Heavy Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			(Cubic Metres per Day)								
Bow River Pipeline Ltd - Heavy												
N Hoosier Blairmore Vol	0.800	0.545	0.255	72	75	67	60	53	47	26	15	8
Plover Lake Bakken Non	0.400	0.124	0.276	80	71	63	57	51	46	29	19	13
Miscellaneous	3.505	1.295	2.210	517	574	538	487	441	399	242	146	89
Pipeline Total	18.124	10.129	7.995	2055	2040	1873	1696	1536	1392	851	521	321
Bow River Pipeline Lt Blend Hvy												
Plato Field Total	0.772	0.344	0.428	152	186	160	138	119	102	27	0	0
Smiley Dewar Viking	4.700	4.021	0.679	230	228	205	184	166	149	87	0	0
Pipeline Total	5.472	4.365	1.107	382	415	366	323	285	251	114	0	0
South Saskatchewan Pipeline Company												
Battrum Unit No One	5.900	4.543	1.357	347	382	346	313	283	256	155	94	0
Battrum Unit No Two	1.737	1.157	0.580	116	132	125	115	106	98	64	42	28
Battrum Unit No Three	2.000	1.186	0.814	140	135	125	116	108	101	75	58	47
Battrum Unit No Four	1.213	0.826	0.387	145	135	117	101	87	75	36	17	0
Beverly Cantuar Sd Non	0.500	0.371	0.129	64	55	47	40	34	29	0	0	0
Beverly U Rose Sd Unit	1.700	1.526	0.174	62	55	48	43	38	34	18	10	0
Bone Crk U Shaun Unit	2.600	2.247	0.353	97	89	81	74	68	62	39	25	16
Butte U Shaun Vol Unit	1.320	0.703	0.617	95	86	79	73	68	63	46	36	29
Cantuar Cantuar Unit	4.410	3.685	0.725	280	260	225	194	168	145	70	33	0
Cantaur L Roseray Unit	1.840	1.477	0.363	165	150	124	103	85	70	27	10	0
Delta U Shaun Unit 1	2.400	2.129	0.271	105	92	81	71	63	55	29	0	0
Dollard U Shaun Unit	13.087	12.404	0.683	400	352	272	209	162	125	34	0	0
Fosterton Main Unit	9.000	8.484	0.516	212	182	156	133	114	97	44	20	1
Gull Lake North Unit	3.215	2.944	0.271	111	96	83	71	62	53	25	12	0
Instow U Shaunavon Unit	8.321	7.186	1.135	360	339	300	264	233	206	110	59	31
N Premier Roseray Ttl	3.952	3.715	0.237	143	114	91	72	58	46	12	0	0
Rapdan Unit	3.100	2.411	0.689	200	199	183	162	144	127	70	38	21
South Success Unit	3.700	3.288	0.412	167	144	124	107	92	79	37	17	0
Suffield Field Total	4.000	2.937	1.063	290	263	238	216	195	177	108	66	40
Verlo Roseray Sd Unit	2.250	1.396	0.854	219	199	180	164	149	135	83	51	32
Miscellaneous	14.640	11.498	3.142	1306	1134	985	856	744	646	320	0	0
Pipeline Total	90.885	76.113	14.772	5030	4603	4019	3508	3068	2689	1413	596	248
Westspur Pipeline Co SE Saskatchewan Medium												
Benson Midale Unit	2.278	1.430	0.848	128	123	117	111	106	100	78	60	46
Ingoldsby Frob Alida N U	1.775	1.470	0.305	80	79	73	66	60	54	33	20	12

Heavy Crude Oil

	Initial Recoverable Reserves at 31/12/84	Cumulative Production To31/12/84	Remaining Reserves At31/12/84	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(Millions of Cubic Metres)			Productive Capacity (Cubic Metres per Day)								
Westspur Pipeline Co SE Saskatchewan Medium												
Innes Frobisher	2.150	1.727	0.423	129	126	112	100	90	80	46	26	0
Lost Horse Hill Frob Alida	3.400	2.647	0.753	210	210	188	168	151	135	78	45	25
Midale Central Mid Unit	17.836	14.620	3.216	775	785	722	660	603	551	351	224	142
Midale Central Mid Non U	1.760	1.108	0.652	159	156	144	132	122	113	75	50	33
Oungre Rat Vol Unit 1	1.910	1.018	0.892	117	112	107	103	98	94	76	61	49
Tatagwa Midale	0.600	0.178	0.422	167	144	125	108	93	80	38	18	0
Viewfield Frob Alida Non	0.914	0.534	0.380	115	108	97	87	78	70	40	23	11
Wapella Wapella Sand	1.891	1.153	0.738	167	180	173	157	142	128	78	47	28
Weyburn Midale Unit	51.800	40.668	11.132	1724	1628	1499	1386	1285	1196	865	657	517
Weyburn Midale Non Unit	2.541	1.121	1.420	370	380	344	311	282	255	154	93	56
Miscellaneous	15.464	9.728	5.736	1750	1763	1623	1446	1289	1149	646	363	0
Pipeline Total	104.319	77.402	26.917	5893	5800	5330	4842	4404	4011	2563	1692	925
Saskatchewan Total	278.134	201.902	76.232	21276	20482	18430	16452	14699	13151	7612	4001	1959
Manitoba												
Transprairie Pipelines												
Kirkella Field Total	0.242	0.207	0.035	28	22	17	13	10	4	0	0	0
Provincial Total	0.242	0.207	0.035	28	22	17	13	10	4	0	0	0
Canada Total	404.108	276.367	127.741	39387	38304	34165	30048	26413	23251	12455	5679	2549

Table A6-4
Historical Data and Projections - Oil Directed Exploratory Drilling and Reserves Additions of Conventional Crude Oil by Primary Recovery - Conventional Areas

	Drilling (Millions of Metres)	Reserves Added (Millions of Cubic Metres)
1965	1.32	69.0
1966	1.20	52.2
1967	1.23	77.0
1968	1.32	69.2
1969	1.33	44.3
1970	0.58	16.1
1971	0.65	25.9
1972	0.49	12.9
1973	0.56	6.7
1974	0.38	0.0
1975	0.32	0.0
1976	0.41	0.0
1977	0.57	26.0
1978	0.93	13.0
1979	1.33	15.0
1980	1.77	18.0
1981	1.58	8.0
1982	1.57	55.0
1983	1.67	33.0
1984	2.51	57.7

					Additions Rate (Cubic Metres per Metre)	
	Low Price Case	High Price Case	Low Price Case	High Price Case	Low Price Case	High Price Case
1985	2.76	2.76	46.0	46.0	16.7	16.7
1986	1.82	1.82	20.1	20.1	11.0	11.0
1987	0.94	1.47	9.5	14.6	10.1	9.9
1988	0.87	1.40	8.3	12.7	9.5	9.1
1989	0.92	1.53	8.3	12.7	9.0	8.3
1990	0.90	1.60	7.7	11.9	8.6	7.4
1995	0.72	1.70	4.6	7.3	6.4	4.3
2000	0.45	1.45	2.4	3.7	5.3	2.6
2005	0.27	1.14	1.3	2.0	4.8	1.8

Note: The historical reserves additions may include some portion of reserves attributable to secondary recovery.

Table A6-5
Reserves Additions and Ultimate Potential of Conventional Crude Oil - Conventional Areas

(Millions of Cubic Metres)		Reserves Additions 1985-2005	
	Ultimate	Low Price Case	High Price Case
EOR in Light Established Pools			
Water flood	81	64	64
Miscible	271	93	116
Chemical	15	0	9
Subtotal	367	157	189
EOR in Heavy Established Pools			
Waterflood	98	27	27
Lloydminster Thermal	215	42	69
Other Thermal	50	8	13
Chemical	15	0	0
Subtotal	378	77	109
EOR Subtotal	745	234	298
New Discoveries and Other Appreciation			
Light	308	171	235
Heavy	125	56	78
Subtotal	432	227	313
Total Reserves Additions			
Light	675	328	424
Heavy	503	133	187
Total	1177	461	611
Initial Established Reserves as of December 31, 1984			
Light	2165		
Heavy	404		
Total	2569		
Ultimate Potentials			
Light	2840		
Heavy	907		
Total	3746		

Notes: For the waterflood, miscible, chemical, Lloydminister and other thermal categories the reserves additions are those which result from enhanced recovery in pools discovered prior to December 31, 1984.

For the discovery category the additions are those which result from new discoveries, enhanced recovery of these discoveries and appreciation other than by enhanced recovery for pools discovered prior to December 31, 1984.

All numbers on this table have been rounded.

Table A6-6
Annual Reserves Additions of Conventional Light Crude Oil - Conventional Areas

(Millions of Cubic Metres)					Low Price Case				
	1985	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Waterflood	5.1	4.0	4.0	3.5	3.5	3.5	3.0	3.0	2.0
Miscible	20.0	2.0	3.0	4.0	4.0	4.0	5.0	3.0	2.0
Chemical	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	25.1	6.0	7.0	7.5	7.5	7.5	8.0	6.0	4.0
Discoveries	35.0	16.1	8.2	7.5	7.8	7.7	6.4	5.3	4.7
Total	60.1	22.1	15.2	15.0	15.3	15.2	14.4	11.3	8.7

					High Price Case				
	1985	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Waterflood	5.1	4.0	4.0	3.5	3.5	3.5	3.0	3.0	2.0
Miscible	20.0	2.0	10.0	25.0	10.0	10.0	3.0	2.0	2.0
Chemical	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	0.0
Subtotal	25.1	6.0	14.0	28.5	13.5	13.5	6.0	6.0	4.0
Discoveries	35.0	16.1	12.6	11.6	12.0	11.8	9.9	8.1	7.2
Total	60.1	22.1	26.6	40.1	25.5	25.3	15.9	14.1	11.2

Notes: For the waterflood, miscible and chemical categories the reserves additions are those which result from enhanced recovery in established pools discovered prior to December 31, 1984.

For the discovery category the additions are those which result from new discoveries, enhanced recovery of these discoveries and appreciation other than by enhanced recovery for pools discovered prior to December 31, 1984.

Table A6-7
Annual Reserves Additions of Conventional Heavy Crude Oil - Conventional Areas

(Millions of Cubic Metres)

Low Price Case

	1985	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Waterflood	2.0	2.0	2.0	2.0	2.0	2.0	2.0	1.0	0.0
Lloydminster Thermal	1.0	0.0	0.0	0.0	0.5	1.0	2.5	3.0	3.5
Other Thermal	0.1	0.0	0.0	0.0	0.0	0.1	0.5	0.6	0.6
Subtotal	3.1	2.0	2.0	2.0	2.5	3.1	5.0	4.6	4.1
Discoveries	11.0	5.4	2.7	2.5	2.6	2.5	2.1	1.8	1.6
Total	14.1	7.4	4.7	4.5	5.1	5.6	7.1	6.4	5.7

High Price Case

	1985	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Waterflood	2.0	2.0	2.0	2.0	2.0	2.0	2.0	1.0	0.0
Lloydminster Thermal	1.0	0.0	0.0	0.0	1.0	2.0	4.0	5.0	6.0
Other Thermal	0.1	0.0	0.0	0.0	0.1	0.2	0.7	1.0	1.0
Subtotal	3.1	2.0	2.0	2.0	3.1	4.2	6.7	7.0	7.0
Discoveries	11.0	5.4	4.2	3.9	4.0	3.9	3.3	2.7	2.4
Total	14.1	7.4	6.2	5.9	7.1	8.1	10.0	9.7	9.4

Notes: For the waterflood, Lloydminster and other thermal categories the reserves additions are those which result from enhanced recovery in pools discovered prior to December 31, 1984.

For the discovery category the additions are those which result from new discoveries, enhanced recovery of these discoveries and appreciation other than by enhanced recovery for pools discovered prior to December 31, 1984.

Table A6-8
Productive Capacity from Reserves Additions of Conventional Light Crude Oil
Conventional Areas

(Thousands of Cubic Metres Per Day)

Low Price Case

	1985	1986	1987	1988	1989	1990	1995	2000	2005
Waterflood	0.0	0.5	1.4	2.1	2.7	3.1	4.7	5.7	5.7
Miscible	0.0	0.8	2.8	3.3	3.9	4.5	6.8	8.5	8.3
Chemical	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	0.0	1.3	4.2	5.4	6.6	7.6	11.5	14.2	14.0
Discoveries	3.4	8.7	11.9	13.9	15.1	15.8	17.7	17.0	15.5
Total	3.4	10.0	16.1	19.3	21.7	23.4	29.2	31.2	29.5

High Price Case

	1985	1986	1987	1988	1989	1990	1995	2000	2005
Waterflood	0.0	0.5	1.4	2.1	2.7	3.1	4.7	5.7	5.7
Miscible	0.0	0.8	2.8	3.6	5.6	8.5	11.8	10.4	8.9
Chemical	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	1.3
Subtotal	0.0	1.3	4.2	5.7	8.3	11.6	16.5	16.6	15.9
Discoveries	3.4	8.7	12.3	15.2	17.3	19.0	24.1	24.4	22.9
Total	3.4	10.0	16.5	20.9	25.6	30.6	40.6	41.0	38.8

Basic assumptions for converting reserves additions to productive capacity.

	Delay	Initial RLI	Percent Decline in RLI	Final RLI
Waterflood	1.0	15.0	0.0	15.0
Miscible	1.3	20.0	10.0	15.0
Chemical	1.3	20.0	10.0	10.0
Discoveries	0.0	14.0	15.0	10.0

The "Delay" is the time in years from booking the reserves to first production.
The "Initial RLI" is the reserves life index (RLI) at the start of production.
The "Percent Decline in RLI" is the rate of deline of the RLI.
The "Final RLI" is the RLI during the declining production phase of the reservoir life.

Table A6-9
Productive Capacity from Reserves Additions of Conventional Heavy Crude Oil
Conventional Areas

(Thousands of Cubic Metres Per Day)

Low Price Case

	1985	1986	1987	1988	1989	1990	1995	2000	2005
Waterflood	0.0	0.2	0.6	0.9	1.3	1.6	2.9	3.0	2.2
Lloydminster Thermal	0.0	0.1	0.3	0.2	0.2	0.3	1.9	4.0	5.8
Other Thermal	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.6	1.0
Subtotal	0.0	0.3	0.9	1.1	1.5	1.9	4.9	7.6	9.0
Discoveries	1.3	3.0	4.1	4.8	5.3	5.5	6.1	5.7	5.2
Total	1.3	3.3	5.0	5.9	6.8	7.4	11.0	13.3	14.2

High Price Case

	1985	1986	1987	1988	1989	1990	1995	2000	2005
Waterflood	0.0	0.2	0.6	0.9	1.3	1.6	2.9	3.0	2.2
Lloydminster Thermal	0.0	0.1	0.3	0.2	0.2	0.3	3.1	6.5	9.6
Other Thermal	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.9	1.6
Subtotal	0.0	0.3	0.9	1.1	1.5	1.9	6.3	10.4	13.4
Discoveries	1.3	3.0	4.2	5.3	6.1	6.7	8.4	8.4	7.7
Total	1.3	3.3	5.1	6.4	7.6	8.6	14.7	18.8	21.1

Basic assumptions for converting reserves additions to productive capacity.

	Delay	Initial RLI	Percent Decline in RLI	Final RLI
Waterflood	1.0	15.0	0.0	15.0
Lloydminster Thermal	1.0	10.0	0.0	10.0
Other Thermal	1.0	20.0	10.0	10.0
Discoveries	0.0	13.0	15.0	9.0

The "Delay" is the time in years from booking the reserves to first production.
The "Initial RLI" is the reserves life index (RLI) at the start of production.
The "Percent Decline in RLI" is the rate of deline of the RLI.
The "Final RLI" is the RLI during the declining production phase of the reservoir life.

Table A6-10
Schedule of Approved Miscible Flood Projects

(Millions of Cubic Metres)			Incremental Reserves
1985	Judy Creek, BHL A	Esso	8.0
	Mitsue, Gilwood A (second stage)	Chevron	2.9
	Nipisi, Gilwood A (second stage)	Amoco	2.5
	Swan Hills, Unit 1, BHL A & B	Home	6.6
	Total		20.0
1986	Bigoray, Nisku F	Chevron	0.8
	Pembina, Nisku F	Texaco	0.6
	Total		1.4
1987	Goose River, BHL	Gulf	3.0
	Judy Creek, BHL B	Esso	3.8
	Meekwap, D2 *	Gulf	1.0
	Mitsue, Gilwood A (third stage) *	Chevron	1.6
	Total		9.4
1988	Acheson, D-3A	Chevron	1.0
	Kaybob, BHL A *	Chevron	6.0
	Nipisi, Gilwood A (third stage) *	Amoco	2.5
	Snipe Lake, BHL *	Esso	2.7
	Virginia Hills, BHL	Shell	8.0
	Swan Hills, Unit 1, BHL A & B (second stage)*	Home	4.6
	Total		24.8

* Scheduled but not yet approved.

Table A6-11
Productive Capacity from Planned Bitumen Projects

(Thousands of Cubic Metres Per Day)					Low Price Case				
	1985	1986	1987	1988	1989	1990	1995	2000	2005
Esso Cold Lake	2.0	7.5	9.0	9.0	9.0	12.0	15.0	15.0	15.0
BP Wolf Lake	0.6	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Amoco Elk Point	0.0	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Dome Lindbergh	0.0	0.1	0.1	0.1	0.6	0.9	0.9	0.9	0.9
Shell Peace River	0.0	0.1	1.3	1.5	1.5	1.5	1.5	1.5	1.5
Dome Primrose	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suncor Burnt Lake	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Murphy Lindbergh	0.0	0.1	0.1	0.1	0.4	0.4	0.4	0.4	0.4
Experimental	5.7	5.4	4.0	3.5	3.0	3.0	3.0	3.0	3.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Potential Supply	8.3	14.5	16.0	15.7	16.0	19.3	22.3	22.3	22.3

					High Price Case				
	1985	1986	1987	1988	1989	1990	1995	2000	2005
Esso Cold Lake	2.0	7.5	9.0	9.0	12.0	15.0	24.0	27.0	30.0
BP Wolf Lake	0.6	1.1	1.1	1.1	1.1	2.6	4.1	5.6	7.1
Amoco Elk Point	0.0	0.2	0.4	1.3	1.3	2.9	3.0	4.2	5.4
Dome Lindbergh	0.0	0.1	0.1	0.5	0.5	0.9	1.8	2.3	2.8
Shell Peace River	0.0	0.1	1.3	1.5	1.5	1.5	3.0	4.5	6.0
Dome Primrose	0.0	0.0	0.4	0.8	0.8	1.6	3.2	4.0	4.8
Suncor Burnt Lake	0.0	0.0	0.0	0.0	0.5	1.0	4.0	5.0	8.0
Murphy Lindbergh	0.0	0.1	0.4	0.4	0.4	0.4	1.2	2.0	2.8
Experimental	5.7	5.4	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Other	0.0	0.0	0.0	0.0	1.0	2.0	6.0	9.0	12.0
Total Potential Supply	8.3	14.5	18.7	20.6	25.1	33.9	56.3	69.6	84.9

Note: The volumes shown are before blending with diluent.

Table A6-12
Synthetic and Frontier Crude Oil Supply

(Thousands of Cubic Metres Per Day)				Low Price Case					
	1985	1986	1987	1988	1989	1990	1995	2000	2005
Suncor	5.8	8.4	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Syncrude	20.3	20.4	20.5	21.0	21.5	21.5	22.5	22.5	22.5
Co-op	0.0	0.0	0.0	3.4	6.8	6.8	6.8	6.8	6.8
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	26.1	28.8	28.5	32.4	36.3	36.3	37.3	37.3	37.3
Hibernia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Beaufort Sea	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	26.1	28.8	28.5	32.4	36.3	36.3	37.3	37.3	37.3
				High Price Case					
Suncor	5.8	8.4	8.0	8.0	8.0	8.0	8.0	8.0	8.0
Syncrude	20.3	20.4	20.5	21.0	21.5	21.5	26.0	26.0	26.0
Co-op	0.0	0.0	0.0	3.4	6.8	6.8	6.8	6.8	6.8
Other	0.0	0.0	0.0	0.0	0.0	0.0	3.8	7.6	7.6
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.6	7.6
Subtotal	26.1	28.8	28.5	32.4	36.3	36.3	44.6	56.0	56.0
Hibernia	0.0	0.0	0.0	0.0	0.0	0.0	3.5	17.5	17.5
Beaufort Sea	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.5	17.5
Subtotal	0.0	0.0	0.0	0.0	0.0	0.0	3.5	35.0	35.0
Total	26.1	28.8	28.5	32.4	36.3	36.3	48.1	91.0	91.0

Table A6-13
Historical Data - Production of Crude Oil and Equivalent - Conventional Areas

(Thousands of Cubic Metres Per Day)

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Conventional Light	101.6	112.7	125.1	132.2	148.4	166.1	176.9	203.6	242.3	230.0
Conventional Heavy	25.7	26.8	27.9	30.1	29.4	31.2	31.8	32.3	35.2	30.3
Synthetic	0.0	0.0	0.2	2.3	4.4	5.2	6.7	8.1	8.0	7.3
Bitumen	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pentanes plus [a]	12.1	12.8	13.4	14.4	16.8	19.2	20.4	26.5	27.0	25.7
Total	139.4	152.3	166.6	179.0	199.0	221.7	235.8	270.5	312.5	293.3

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Conventional Light	194.7	174.1	169.3	165.6	188.7	173.7	154.5	150.7	153.3	164.5	158.7
Conventional Heavy	25.2	24.6	30.8	32.2	31.8	31.1	27.9	28.7	33.0	37.6	40.7
Synthetic	6.8	7.6	7.2	8.9	14.6	20.3	17.7	19.1	25.4	21.1	26.1
Bitumen	0.0	1.2	1.2	1.2	1.5	1.5	2.0	3.2	4.0	5.3	8.3
Pentanes plus [a]	24.1	21.3	21.1	18.9	18.8	17.0	16.2	15.9	14.8	15.5	16.4
Total	250.8	228.8	229.6	226.8	255.4	243.6	218.3	217.6	230.5	244.0	250.2

Note: [a] Includes condensate.

Table A6-14
Productive Capacity of Crude Oil and Equivalent - Total Canada

(Thousands of Cubic Metres Per Day)

Low Price Case

	Light								Heavy						
	Light Estab- lished	Light Addi- tions	Pentanes Plus [a]	Mining Syn- thetic	Upgraded Heavy	Frontier	Diluent [b]	Light Total	Heavy Estab- lished	Heavy Addi- tions	Bitumen	Diluent	Upgrader Feed- stock	Heavy Total	Total Crude & Equiv- alent
1985	164.7	3.4	16.4	26.1	0.0	0.0	-6.3	204.3	39.4	1.3	8.3	6.3	0.0	55.3	259.6
1986	158.0	10.0	16.2	28.8	0.0	0.0	-8.7	204.3	37.9	3.3	14.5	8.7	0.0	64.4	268.7
1987	142.2	16.0	16.4	28.5	0.0	0.0	-9.0	194.1	33.1	5.0	16.0	9.0	0.0	63.1	257.2
1988	123.7	19.3	17.2	29.0	3.4	0.0	-8.5	184.0	28.5	6.0	15.7	8.5	-4.0	54.7	238.8
1989	108.3	21.7	18.1	29.5	6.8	0.0	-8.4	176.0	25.1	6.8	16.0	8.4	-8.0	48.3	224.3
1990	95.0	23.4	17.2	29.5	6.8	0.0	-9.4	162.5	22.1	7.4	19.3	9.4	-8.0	50.2	212.7
1991	83.6	24.8	16.2	29.5	6.8	0.0	-9.5	151.4	19.5	8.1	20.0	9.5	-8.0	49.1	200.5
1992	73.9	26.1	15.3	29.5	6.8	0.0	-9.7	142.0	17.2	8.7	20.8	9.7	-8.0	48.4	190.3
1993	65.7	27.3	14.8	29.5	6.8	0.0	-9.8	134.3	15.2	9.4	21.5	9.8	-8.0	47.9	182.2
1994	58.6	28.3	14.4	30.0	6.8	0.0	-9.9	128.2	13.5	10.2	22.0	9.9	-8.0	47.6	175.8
1995	52.5	29.1	13.7	30.5	6.8	0.0	-10.0	122.6	11.8	11.0	22.5	10.0	-8.0	47.3	169.9
1996	47.1	29.8	13.1	30.5	6.8	0.0	-9.9	117.4	10.4	11.7	22.5	9.9	-8.0	46.5	163.9
1997	42.2	30.4	12.4	30.5	6.8	0.0	-9.9	112.4	9.1	12.3	22.5	9.9	-8.0	45.8	158.2
1998	38.0	30.8	12.0	30.5	6.8	0.0	-9.8	108.3	7.9	12.6	22.5	9.8	-8.0	44.8	153.1
1999	34.1	31.0	11.9	30.5	6.8	0.0	-9.7	104.6	6.4	12.9	22.5	9.7	-8.0	43.5	148.1
2000	30.6	31.1	10.9	30.5	6.8	0.0	-9.6	100.3	5.4	13.3	22.5	9.6	-8.0	42.8	143.1
2001	26.7	31.0	9.8	30.5	6.8	0.0	-9.6	95.3	4.6	13.7	22.5	9.6	-8.0	42.4	137.6
2002	23.9	30.8	8.8	30.5	6.8	0.0	-9.5	91.3	3.8	13.9	22.5	9.5	-8.0	41.7	133.0
2003	21.2	30.5	8.0	30.5	6.8	0.0	-9.5	87.5	3.2	14.0	22.5	9.5	-8.0	41.2	128.7
2004	18.9	30.1	7.2	30.5	6.8	0.0	-9.4	84.0	2.8	14.1	22.5	9.4	-8.0	40.8	124.9
2005	17.0	29.6	6.5	30.5	6.8	0.0	-9.4	81.0	2.4	14.2	22.5	9.4	-8.0	40.5	121.5

Note: [a] Includes condensate

[b] Approximately five thousand cubic metres per day of pentanes plus are not available as heavy oil diluent.
Diluent requirements in excess of the supply of pentanes plus are assumed to be met by a light oil fraction.

Table A6-14 (Continued)
Productive Capacity of Crude Oil and Equivalent - Total Canada

(Thousands of Cubic Metres Per Day)

High Price Case

	Light								Heavy						
	Light Estab-lished	Light Addi-tions	Pentanes Plus [a]	Mining Syn-thetic	Upgraded Heavy	Frontier	Diluent [b]	Light Total	Heavy Estab-lished	Heavy Addi-tions	Bitumen	Diluent	Upgrader Feed-stock	Heavy Total	Total Crude & Equiv-alent
1985	164.7	3.4	16.4	26.1	0.0	0.0	-6.3	204.3	39.4	1.3	8.3	6.3	0.0	55.3	259.6
1986	158.8	10.0	16.2	28.8	0.0	0.0	-8.8	205.0	38.3	3.3	14.5	8.8	0.0	64.9	269.9
1987	143.6	16.5	16.3	28.5	0.0	0.0	-10.2	194.7	34.2	5.1	18.7	10.2	0.0	68.2	262.9
1988	126.2	20.9	16.9	29.0	3.4	0.0	-10.6	185.8	30.0	6.5	20.6	10.6	-4.0	63.7	249.5
1989	110.5	25.7	17.7	29.5	6.8	0.0	-12.1	178.1	26.4	7.6	25.1	12.1	-8.0	63.2	241.3
1990	96.9	30.7	16.7	29.5	6.8	0.0	-15.3	165.3	23.3	8.6	33.9	15.3	-8.0	73.1	238.4
1991	85.3	34.1	15.6	30.5	6.8	0.0	-17.6	154.7	20.5	9.8	40.0	17.6	-8.0	79.9	234.6
1992	75.4	36.9	14.6	32.5	6.8	0.0	-19.0	147.3	18.1	11.0	44.0	19.0	-8.0	84.1	231.3
1993	67.0	38.6	14.0	32.5	6.8	0.0	-20.5	138.4	16.0	12.2	48.0	20.5	-8.0	88.7	227.1
1994	59.8	39.8	13.6	33.0	6.8	0.0	-22.0	131.0	14.2	13.4	52.0	22.0	-8.0	93.6	224.6
1995	53.6	40.6	12.8	34.0	10.6	3.5	-22.6	132.5	12.5	14.6	56.0	22.6	-12.0	93.7	226.2
1996	48.1	41.0	12.0	34.0	14.4	19.5	-22.5	146.5	10.9	15.8	58.0	22.5	-16.0	91.2	237.7
1997	43.1	41.2	11.3	34.0	14.4	35.0	-23.7	155.3	9.5	16.7	61.0	23.7	-16.0	94.9	250.2
1998	38.8	41.2	10.9	34.0	14.4	35.0	-24.8	149.5	8.3	17.4	64.0	24.8	-16.0	98.5	248.0
1999	34.8	41.1	10.7	34.0	18.2	35.0	-24.3	149.5	6.7	18.0	67.0	24.3	-20.0	96.0	245.5
2000	31.2	40.9	10.6	34.0	22.0	35.0	-23.9	149.8	5.7	18.7	70.0	23.9	-24.0	94.3	244.1
2001	27.3	40.7	10.8	34.0	22.0	35.0	-25.0	144.8	4.8	19.4	73.0	25.0	-24.0	98.2	243.0
2002	24.4	40.3	11.1	34.0	22.0	35.0	-26.2	140.6	4.0	20.0	76.0	26.2	-24.0	102.2	242.8
2003	21.6	39.8	11.1	34.0	22.0	35.0	-27.3	136.2	3.4	20.4	79.0	27.3	-24.0	106.1	242.3
2004	19.3	39.4	10.9	34.0	22.0	35.0	-28.5	132.2	2.9	20.7	82.0	28.5	-24.0	110.1	242.2
2005	17.4	38.9	10.5	34.0	22.0	35.0	-29.6	128.2	2.5	21.1	85.0	29.6	-24.0	114.2	242.4

Note: [a] Includes condensate

[b] Approximately five thousand cubic metres per day of pentanes plus are not available as heavy oil diluent.
Diluent requirements in excess of the supply of pentanes plus are assumed to be met by a light oil fraction.

Table A6-15
Historical Data - Primary Demand and Supply for Oil - Canada

(Petajoules)	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Sectoral Demand										
Residential	524.7	515.8	540.3	568.4	586.7	618.7	614.4	646.1	610.0	641.4
Commercial	193.9	222.4	247.9	284.4	293.8	308.6	306.9	326.8	286.2	272.7
Industrial	338.1	354.8	393.5	408.2	447.9	477.4	477.3	503.5	542.0	553.9
Transportation	975.6	1038.6	1096.3	1157.6	1200.1	1265.6	1313.5	1407.9	1535.9	1597.9
Non-Energy [a]	170.6	185.1	188.7	193.7	211.3	252.7	256.3	281.4	321.2	318.3
Total End Use	2202.9	2316.8	2466.7	2612.3	2739.8	2923.0	2968.3	3165.7	3295.3	3384.2
Own Use	162.0	167.9	175.2	182.8	186.1	201.1	212.9	225.4	247.4	249.1
Electricity Generation	35.8	39.6	56.3	82.0	79.5	106.6	108.3	108.7	112.2	117.8
Steam Production	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Butanes for Blending	-6.5	-9.2	-8.8	-9.3	-8.8	-7.5	-5.0	-11.2	-17.1	-16.8
Refinery LPG	1.3	2.0	20.9	18.8	20.3	24.2	24.6	28.1	27.3	29.4
Total Primary Demand [b]	2395.5	2517.0	2710.3	2886.5	3016.9	3247.3	3309.1	3516.8	3665.1	3763.7
Fuels for Electricity Export	0.0	0.0	0.0	0.0	0.0	3.5	4.6	4.4	4.1	4.2
Sub Total	2395.5	2517.0	2710.3	2886.5	3016.9	3250.8	3313.7	3521.2	3669.2	3767.9
Exports	676.7	777.8	928.6	1037.8	1243.8	1499.5	1691.9	2339.7	2797.4	2276.6
Total Disposition	3072.2	3294.8	3638.9	3924.3	4260.7	4750.3	5005.6	5860.9	6466.6	6044.5
Imports	1243.2	919.2	1029.9	1130.4	1230.3	1319.8	1523.0	2038.8	2242.4	1941.4
Production	2011.0	2196.0	2401.0	2580.0	2868.0	3196.0	3400.0	3900.0	4504.0	4227.0
Primary Supply	3254.2	3115.2	3430.9	3710.4	4098.3	4515.8	4923.0	5938.8	6746.4	6168.4

Source: "Quarterly Report on Energy Supply - Demand in Canada"
Statistics Canada #57-003.
Note: [a] Includes Petrochemicals.
[b] Equivalent to Total Oil Products plus Refinery LPG, Table A6-16.

(Petajoules)	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Sectoral Demand										
Residential	612.4	600.5	541.3	523.4	513.1	492.4	401.8	371.6	326.6	278.6
Commercial	212.6	261.5	228.8	245.5	216.0	208.1	194.6	174.2	162.8	147.4
Industrial	539.4	528.6	560.1	530.7	545.6	509.4	452.5	371.3	321.6	319.3
Transportation	1622.8	1690.5	1736.4	1796.8	1922.2	1958.1	1908.1	1739.0	1668.4	1709.6
Non-Energy [a]	302.5	310.3	350.1	379.4	421.6	387.5	379.6	308.6	295.3	306.8
Total End Use	3289.7	3391.4	3416.7	3475.8	3618.5	3555.4	3336.5	2964.6	2774.7	2761.6
Own Use	249.4	237.8	259.8	277.2	280.3	267.8	251.3	225.9	209.6	223.3
Electricity Generation	120.3	133.0	108.0	126.0	110.2	104.8	90.2	84.8	55.3	43.9
Steam Production	0.0	0.0	0.0	0.0	12.0	12.4	9.6	8.6	7.4	6.3
Butanes for Blending	-30.8	-25.2	-25.5	-26.3	-18.1	-25.5	-24.3	-27.0	-29.8	-44.1
Refinery LPG	37.4	52.5	57.3	59.1	66.8	61.9	57.5	61.1	69.4	65.1
Total Primary Demand [b]	3666.0	3789.5	3816.2	3911.8	4069.8	3976.8	3720.8	3318.0	3086.6	3056.1
Fuels for Electricity Export	4.9	12.5	31.2	22.8	29.2	27.3	7.5	6.5	14.5	18.6
Sub Total	3670.9	3802.0	3847.4	3934.6	4099.0	4004.1	3728.3	3324.5	3101.1	3074.7
Exports	1773.3	1172.3	779.8	678.9	605.7	489.7	494.1	551.3	884.6	1013.5
Total Disposition	5444.2	4974.3	4627.2	4613.5	4704.7	4493.8	4222.4	3875.7	3985.7	4088.2
Imports	1916.0	1770.2	1472.8	1330.4	1141.9	1078.3	1125.3	717.2	611.8	668.6
Production	3616.0	3299.0	3310.0	3270.0	3682.0	3512.0	3149.0	3137.0	3323.0	3516.0
Primary Supply	5532.0	5069.2	4782.8	4600.4	4823.9	4590.3	4274.3	3854.2	3934.8	4184.6

Source: "Quarterly Report on Energy Supply - Demand in Canada"
Statistics Canada #57-003.
Note: [a] Includes Petrochemicals.
[b] Equivalent to Total Oil Products plus Refinery LPG, Table A6-16.

Table A6-16
Total Petroleum Product Demand - Canada and Regions

(Petajoules) **Canada**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	5.9	6.1	6.0	6.0	5.9	5.8	5.7	5.5	5.0	5.0
Motor Gasoline [a]	1097.6	1101.5	1093.1	1087.8	1088.1	1092.6	1101.0	1166.8	1231.8	1290.2
Av. Turbo - Kerosene (Jet A-1)	108.5	118.0	123.7	130.8	136.9	140.7	142.3	159.2	176.3	192.3
- Naphtha (Jet B)	40.4	36.3	35.3	34.6	33.4	31.5	29.1	30.3	31.1	33.9
- Total	148.9	154.3	159.0	165.4	170.3	172.2	171.4	189.6	207.4	226.3
Light Fuel and Kerosene	343.4	319.7	318.5	314.7	310.2	304.7	297.4	263.1	243.2	247.4
Diesel Fuel Oil	577.5	582.7	611.8	633.1	650.8	666.8	676.2	735.0	820.8	919.0
Heavy Fuel Oil	330.3	290.0	324.0	339.5	343.8	363.6	324.7	279.3	273.5	343.0
Asphalt	105.7	120.4	124.0	127.1	131.2	133.2	133.9	144.8	158.8	177.4
Lubes and Greases	36.4	36.4	37.7	39.0	40.3	41.8	43.2	49.9	56.2	64.2
Petrochemical Feedstock	122.6	135.0	130.4	117.2	98.1	99.9	101.0	103.2	103.4	103.7
Other Products	222.8	241.0	246.1	249.1	250.8	254.8	255.3	268.2	285.8	312.3
Total Oil Products [a]	2991.0	2987.0	3050.8	3079.0	3089.5	3135.3	3110.0	3205.4	3386.0	3688.5
Refinery LPG	65.1	74.0	76.2	78.9	80.9	82.9	83.6	86.9	91.6	98.6
Total Products plus Refinery LPG [b]	3056.1	3061.0	3126.9	3157.8	3170.3	3218.2	3193.6	3292.3	3477.6	3787.1

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	5.9	6.1	6.0	6.0	5.9	5.8	5.7	5.5	5.0	5.0
Motor Gasoline [a]	1097.6	1101.5	1089.7	1079.6	1073.3	1070.1	1067.8	1070.0	1078.5	1089.9
Av. Turbo - Kerosene (Jet A-1)	108.5	118.0	121.7	127.5	132.0	134.4	134.9	140.1	145.3	153.1
- Naphtha (Jet B)	40.4	36.3	34.7	33.7	32.2	30.1	27.6	26.7	25.6	27.0
- Total	148.9	154.3	156.4	161.2	164.1	164.5	162.6	166.8	170.9	180.2
Light Fuel and Kerosene	343.4	319.7	311.7	303.4	293.6	283.0	272.1	207.9	175.4	163.1
Diesel Fuel Oil	577.5	582.7	610.0	627.1	640.8	652.4	658.6	699.6	766.1	835.7
Heavy Fuel Oil	330.3	290.0	317.2	331.9	328.7	346.0	307.5	231.7	225.5	245.2
Asphalt	105.7	120.4	124.0	126.6	129.1	131.7	132.9	144.5	156.7	172.6
Lubes and Greases	36.4	36.4	37.3	38.1	39.0	40.0	40.9	45.6	50.6	56.9
Petrochemical Feedstock	122.6	135.0	130.4	117.1	98.0	99.8	100.9	103.0	103.0	103.1
Other Products	222.8	241.0	244.6	246.0	245.6	247.8	246.6	249.3	259.0	273.7
Total Oil Products [a]	2991.0	2987.0	3027.2	3036.9	3018.2	3041.0	2995.5	2923.9	2990.6	3125.4
Refinery LPG	65.1	74.0	74.7	77.0	78.6	80.1	80.5	81.3	84.2	88.4
Total Products plus Refinery LPG [b]	3056.1	3061.0	3102.0	3114.0	3096.8	3121.1	3076.0	3005.2	3074.8	3213.8

Note :[a] Excludes Butanes for Blending.
[b] Fuels used to generate electricity exports are not included.

(Petajoules)

Atlantic

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	0.4	0.6	0.6	0.6	0.5	0.5	0.5	0.4	0.3	0.3
Motor Gasoline [a]	95.4	94.3	93.7	93.2	93.0	92.9	93.2	95.9	100.0	105.2
Av. Turbo - Kerosene (Jet A-1)	9.0	9.0	9.4	10.0	10.4	10.7	10.8	12.1	13.4	14.6
- Naphtha (Jet B)	6.9	7.1	6.9	6.7	6.5	6.1	5.7	5.9	6.0	6.6
- Total	15.9	16.0	16.3	16.7	16.9	16.8	16.5	18.0	19.5	21.2
Light Fuel and Kerosene	71.5	72.7	72.7	73.3	73.1	73.2	73.4	71.7	68.3	72.4
Diesel Fuel Oil	59.8	56.1	60.7	63.8	66.0	67.4	68.1	74.0	84.8	97.0
Heavy Fuel Oil	97.2	120.6	128.7	133.4	143.7	151.6	125.7	101.7	93.7	102.9
Asphalt	10.5	12.1	12.4	12.8	13.2	13.4	13.4	14.5	15.9	17.8
Lubes and Greases	2.6	2.3	2.4	2.4	2.5	2.5	2.6	2.9	3.2	3.7
Petrochemical Feedstock	0.9	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2
Other Products	12.1	12.8	13.1	13.4	13.8	14.1	13.3	12.9	13.2	14.3
Total Oil Products [a]	366.3	388.6	401.8	410.6	423.8	433.7	407.9	393.3	400.2	436.0
Refinery LPG	7.2	7.2	7.4	7.6	7.8	7.9	7.7	7.7	8.1	8.8
Total Products plus Refinery LPG [b]	373.5	395.8	409.2	418.2	431.6	441.6	415.5	401.0	408.3	444.8

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	0.4	0.6	0.6	0.6	0.5	0.5	0.5	0.4	0.3	0.3
Motor Gasoline [a]	95.4	94.3	93.6	92.8	92.1	91.7	91.3	90.8	92.5	94.4
Av. Turbo - Kerosene (Jet A-1)	9.0	9.0	9.3	9.7	10.0	10.2	10.3	10.7	11.1	11.7
- Naphtha (Jet B)	6.9	7.1	6.8	6.6	6.3	5.9	5.4	5.2	5.0	5.3
- Total	15.9	16.0	16.0	16.3	16.3	16.1	15.6	15.9	16.0	16.9
Light Fuel and Kerosene	71.5	72.7	72.0	72.0	71.4	71.4	73.0	64.3	61.4	65.7
Diesel Fuel Oil	59.8	56.1	60.3	62.8	64.6	65.7	66.2	70.0	79.8	90.1
Heavy Fuel Oil	97.2	120.6	130.0	137.7	146.3	155.9	134.0	90.9	95.0	108.5
Asphalt	10.5	12.1	12.4	12.7	13.0	13.2	13.3	14.5	15.7	17.3
Lubes and Greases	2.6	2.3	2.4	2.4	2.4	2.5	2.5	2.7	3.1	3.4
Petrochemical Feedstock	0.9	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2
Other Products	12.1	12.8	13.1	13.4	13.7	14.1	13.4	11.9	12.4	13.5
Total Oil Products [a]	366.3	388.6	401.4	411.6	421.5	432.2	411.1	362.7	377.6	411.5
Refinery LPG	7.2	7.2	6.7	6.8	6.9	7.1	6.9	6.6	7.0	7.5
Total Products plus Refinery LPG [b]	373.5	395.8	408.1	418.5	428.5	439.3	418.0	369.3	384.6	419.0

Note : [a] Excludes Butanes for Blending.
[b] Fuels used to generate electricity exports are not included.

Table A6-16 (Continued)
Total Petroleum Product Demand - Canada and Regions

(Petajoules) — Quebec

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.7	0.7
Motor Gasoline [a]	233.3	232.6	227.8	224.1	222.1	221.5	222.5	236.8	249.5	260.6
Av. Turbo - Kerosene (Jet A-1)	25.6	27.5	28.8	30.5	31.9	32.8	33.2	37.1	41.1	44.8
- Naphtha (Jet B)	3.7	2.8	2.7	2.7	2.6	2.4	2.3	2.3	2.4	2.6
- Total	29.3	30.3	31.6	33.2	34.5	35.2	35.4	39.5	43.5	47.5
Light Fuel and Kerosene	119.5	104.6	104.2	102.0	98.9	95.6	91.5	73.8	65.7	62.7
Diesel Fuel Oil	93.4	94.6	100.5	105.4	109.8	113.7	116.2	130.7	145.7	155.7
Heavy Fuel Oil	114.1	81.5	90.3	92.7	91.3	108.0	100.4	91.0	90.3	112.9
Asphalt	26.1	28.9	29.8	30.5	31.5	32.0	32.2	34.8	38.2	42.7
Lubes and Greases	6.0	5.8	6.0	6.2	6.4	6.6	6.8	7.6	8.5	9.7
Petrochemical Feedstock	21.3	16.6	17.0	17.5	18.0	19.1	20.0	22.1	22.1	22.1
Other Products	63.7	65.6	66.8	67.5	68.1	69.7	69.8	72.9	77.2	83.2
Total Oil Products [a]	707.6	661.5	674.9	680.1	681.4	702.3	695.8	709.9	741.4	797.8
Refinery LPG	14.4	16.0	16.5	16.8	16.9	17.7	17.9	18.5	19.3	20.7
Total Products plus Refinery LPG [b]	722.0	677.5	691.4	696.9	698.3	720.0	713.7	728.4	760.7	818.5

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.7	0.7
Motor Gasoline [a]	233.3	232.6	227.2	222.6	219.1	216.8	215.0	212.7	212.7	215.9
Av. Turbo - Kerosene (Jet A-1)	25.6	27.5	28.4	29.7	30.8	31.3	31.5	32.7	33.9	35.7
- Naphtha (Jet B)	3.7	2.8	2.7	2.6	2.5	2.3	2.1	2.1	2.0	2.1
- Total	29.3	30.3	31.1	32.3	33.3	33.7	33.6	34.7	35.9	37.8
Light Fuel and Kerosene	119.5	104.6	102.4	98.8	94.1	89.0	83.2	57.9	45.1	38.4
Diesel Fuel Oil	93.4	94.6	100.1	104.1	107.7	110.7	112.5	123.3	134.2	139.1
Heavy Fuel Oil	114.1	81.5	87.7	88.9	85.6	99.3	89.0	72.7	67.4	74.8
Asphalt	26.1	28.9	29.8	30.4	31.0	31.7	32.0	34.8	37.7	41.5
Lubes and Greases	6.0	5.8	6.0	6.1	6.3	6.4	6.6	7.2	8.0	8.9
Petrochemical Feedstock	21.3	16.6	17.0	17.5	18.0	19.0	20.0	22.0	22.0	22.0
Other Products	63.7	65.6	66.4	66.8	66.9	68.1	67.6	68.3	70.6	74.4
Total Oil Products [a]	707.6	661.5	668.5	668.6	662.8	675.4	660.3	634.4	634.2	653.6
Refinery LPG	14.4	16.0	15.5	15.6	15.6	16.2	16.3	16.0	16.2	16.8
Total Products plus Refinery LPG [b]	722.0	677.5	684.0	684.2	678.3	691.7	676.5	650.4	650.4	670.4

Note : [a] Excludes Butanes for Blending.
[b] Fuels used to generate electricity exports are not included.

(Petajoules)

Ontario

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.2	1.3
Motor Gasoline [a]	399.1	402.2	403.4	406.9	413.4	421.6	431.2	477.8	507.9	531.8
Av. Turbo - Kerosene (Jet A-1)	39.4	44.6	46.8	49.5	51.8	53.2	53.8	60.2	66.7	72.8
- Naphtha (Jet B)	7.8	6.4	6.3	6.1	5.9	5.6	5.2	5.4	5.5	6.0
- Total	47.3	51.1	53.1	55.6	57.7	58.8	59.0	65.6	72.2	78.8
Light Fuel and Kerosene	106.1	97.3	99.2	98.0	97.5	95.6	92.8	81.2	74.9	80.3
Diesel Fuel Oil	148.5	149.1	158.5	166.9	174.0	179.7	183.2	200.9	222.7	246.3
Heavy Fuel Oil	80.8	52.0	66.6	73.0	69.2	66.8	64.2	58.6	65.5	105.3
Asphalt	30.9	31.3	32.2	33.1	34.1	34.6	34.8	37.7	41.3	46.2
Lubes and Greases	16.3	17.7	18.5	19.3	20.1	20.9	21.8	25.4	28.7	32.8
Petrochemical Feedstock	97.6	108.3	102.0	87.0	66.2	66.2	66.2	66.4	66.5	66.8
Other Products	89.6	103.1	106.0	107.5	107.8	109.7	110.9	118.8	127.6	141.2
Total Oil Products [a]	1017.6	1013.7	1040.9	1048.7	1041.3	1055.4	1065.7	1133.7	1208.4	1330.8
Refinery LPG	18.7	27.7	28.9	31.1	32.8	33.8	34.6	36.7	38.6	41.5
Total Products plus Refinery LPG [b]	1036.3	1041.4	1069.8	1079.8	1074.1	1089.2	1100.3	1170.4	1247.0	1372.3

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.2	1.3
Motor Gasoline [a]	399.1	402.2	402.0	403.5	406.5	410.7	414.8	429.8	432.8	434.8
Av. Turbo - Kerosene (Jet A-1)	39.4	44.6	46.0	48.3	49.9	50.9	51.1	53.0	55.0	57.9
- Naphtha (Jet B)	7.8	6.4	6.2	6.0	5.7	5.3	4.9	4.7	4.5	4.8
- Total	47.3	51.1	52.2	54.2	55.6	56.2	56.0	57.7	59.5	62.7
Light Fuel and Kerosene	106.1	97.3	96.3	93.1	90.1	85.8	80.7	58.1	45.1	37.9
Diesel Fuel Oil	148.5	149.1	157.7	164.1	169.3	173.4	175.7	186.5	201.1	215.3
Heavy Fuel Oil	80.8	52.0	63.8	69.5	64.2	60.5	56.6	45.5	44.4	45.2
Asphalt	30.9	31.3	32.2	32.9	33.6	34.3	34.6	37.6	40.8	44.9
Lubes and Greases	16.3	17.7	18.2	18.6	19.1	19.6	20.1	22.3	24.7	28.1
Petrochemical Feedstock	97.6	108.3	102.0	87.0	66.1	66.1	66.1	66.1	66.2	66.2
Other Products	89.6	103.1	105.1	105.5	104.7	105.3	105.4	107.5	111.2	116.7
Total Oil Products [a]	1017.6	1013.7	1030.9	1029.9	1010.7	1013.2	1011.2	1012.6	1027.0	1053.2
Refinery LPG	18.7	27.7	26.4	28.4	29.9	30.7	31.3	32.1	32.9	34.1
Total Products plus Refinery LPG [b]	1036.3	1041.4	1057.3	1058.3	1040.6	1043.9	1042.5	1044.7	1059.9	1087.2

Note : [a] Excludes Butanes for Blending.
[b]Fuels used to generate electricity exports are not included.

Table A6-16 (Continued)
Total Petroleum Product Demand - Canada and Regions

(Petajoules) **Manitoba**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6
Motor Gasoline [a]	51.3	50.8	49.8	49.1	48.7	48.5	48.5	51.5	57.0	61.5
Av. Turbo - Kerosene (Jet A-1)	4.1	4.2	4.4	4.7	4.9	5.0	5.1	5.7	6.3	6.9
- Naphtha (Jet B)	2.1	2.0	1.9	1.9	1.8	1.7	1.6	1.6	1.7	1.8
- Total	6.2	6.2	6.3	6.6	6.7	6.7	6.7	7.3	8.0	8.7
Light Fuel and Kerosene	5.4	4.7	4.7	4.5	4.2	3.9	3.7	3.1	2.8	3.0
Diesel Fuel Oil	31.5	34.4	35.1	36.8	38.1	39.4	40.3	45.6	51.8	58.0
Heavy Fuel Oil	2.4	2.5	2.9	2.8	2.6	2.5	2.3	1.9	1.7	1.4
Asphalt	2.2	2.2	2.3	2.3	2.4	2.4	2.4	2.6	2.9	3.2
Lubes and Greases	1.4	1.3	1.4	1.4	1.5	1.5	1.6	1.8	2.1	2.4
Petrochemical Feedstock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Products	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.6	0.7
Total Oil Products [a]	101.4	103.2	103.6	104.6	105.2	106.1	106.6	115.1	127.5	139.6
Refinery LPG	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6
Total Products plus Refinery LPG [b]	101.7	103.7	104.1	105.1	105.7	106.6	107.1	115.7	128.1	140.2

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6
Motor Gasoline [a]	51.3	50.8	49.7	48.9	48.2	47.7	47.3	47.4	49.7	51.6
Av. Turbo - Kerosene (Jet A-1)	4.1	4.2	4.4	4.6	4.7	4.8	4.8	5.0	5.2	5.5
- Naphtha (Jet B)	2.1	2.0	1.9	1.8	1.7	1.6	1.5	1.4	1.4	1.5
- Total	6.2	6.2	6.2	6.4	6.5	6.4	6.3	6.5	6.6	7.0
Light Fuel and Kerosene	5.4	4.7	4.4	4.1	3.7	3.3	2.9	1.4	1.5	1.6
Diesel Fuel Oil	31.5	34.4	34.9	36.2	37.2	38.2	38.9	43.1	48.1	52.6
Heavy Fuel Oil	2.4	2.5	2.7	2.6	2.4	2.3	2.2	2.0	1.7	1.3
Asphalt	2.2	2.2	2.3	2.3	2.4	2.4	2.4	2.6	2.9	3.2
Lubes and Greases	1.4	1.3	1.3	1.4	1.4	1.4	1.5	1.7	1.9	2.1
Petrochemical Feedstock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Products	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.6	0.6
Total Oil Products [a]	101.4	103.2	102.6	103.0	102.9	103.0	102.7	105.9	113.5	120.6
Refinery LPG	0.3	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total Products plus Refinery LPG [b]	101.7	103.7	102.9	103.3	103.2	103.3	103.1	106.2	113.9	121.0

Note : [a] Excludes Butanes for Blending.
[b] Fuels used to generate electricity exports are not included.

(Petajoules)

Saskatchewan

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3
Motor Gasoline [a]	64.6	64.3	62.7	61.2	59.8	58.8	58.1	58.2	62.4	68.0
Av. Turbo - Kerosene (Jet A-1)	0.2	0.8	0.8	0.9	0.9	1.0	1.0	1.1	1.2	1.3
- Naphtha (Jet B)	2.8	2.2	2.2	2.1	2.0	1.9	1.8	1.9	1.9	2.1
- Total	3.0	3.0	3.0	3.0	3.0	2.9	2.8	2.9	3.1	3.4
Light Fuel and Kerosene	9.3	9.2	9.2	8.5	8.1	7.7	7.5	6.0	5.6	5.5
Diesel Fuel Oil	43.5	44.1	44.1	45.0	45.7	46.8	47.5	50.1	56.3	63.1
Heavy Fuel Oil	3.2	2.8	3.1	2.7	2.2	1.9	1.5	1.0	0.7	0.7
Asphalt	5.8	7.4	7.6	7.8	8.1	8.2	8.2	8.9	9.8	10.9
Lubes and Greases	1.9	1.7	1.8	1.9	1.9	2.0	2.1	2.4	2.7	3.1
Petrochemical Feedstock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Products	5.5	5.9	6.0	5.9	5.9	6.0	6.0	6.2	6.8	7.4
Total Oil Products [a]	137.2	138.7	137.9	136.4	135.1	134.7	134.0	136.2	147.6	162.4
Refinery LPG	3.0	2.9	2.9	2.9	2.9	2.9	2.8	2.9	3.1	3.4
Total Products plus Refinery LPG [b]	140.2	141.7	140.8	139.2	138.0	137.6	136.8	139.1	150.7	165.9

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3
Motor Gasoline [a]	64.6	64.3	62.6	60.8	59.2	57.9	56.9	54.6	55.7	57.9
Av. Turbo - Kerosene (Jet A-1)	0.2	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0
- Naphtha (Jet B)	2.8	2.2	2.1	2.1	2.0	1.8	1.7	1.6	1.6	1.7
- Total	3.0	3.0	3.0	2.9	2.9	2.8	2.6	2.6	2.6	2.7
Light Fuel and Kerosene	9.3	9.2	8.9	8.1	7.5	7.1	6.6	4.6	3.7	3.4
Diesel Fuel Oil	43.5	44.1	43.8	44.2	44.5	45.2	45.5	46.5	51.4	56.4
Heavy Fuel Oil	3.2	2.8	2.8	2.5	2.3	2.3	2.0	2.0	1.1	0.7
Asphalt	5.8	7.4	7.6	7.8	7.9	8.1	8.2	8.9	9.6	10.6
Lubes and Greases	1.9	1.7	1.8	1.8	1.9	2.0	2.0	2.3	2.6	2.9
Petrochemical Feedstock	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Products	5.5	5.9	5.9	5.9	5.9	5.9	5.9	6.0	6.4	6.8
Total Oil Products [a]	137.2	138.7	136.6	134.4	132.5	131.5	130.1	127.8	133.4	141.6
Refinery LPG	3.0	2.9	2.9	2.9	2.8	2.8	2.8	2.8	2.9	3.1
Total Products plus Refinery LPG [b]	140.2	141.7	139.5	137.3	135.4	134.3	132.9	130.6	136.3	144.7

Note : [a] Excludes Butanes for Blending.
[b] Fuels used to generate electricity exports are not included.

Table A6-16 (Continued)
Total Petroleum Product Demand - Canada and Regions

(Petajoules)	Alberta									
	Low Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6
Motor Gasoline [a]	124.0	130.5	129.4	127.9	126.5	125.1	124.0	122.8	126.4	129.8
Av. Turbo - Kerosene (Jet A-1)	17.6	17.3	18.1	19.1	20.0	20.6	20.8	23.3	25.8	28.1
- Naphtha (Jet B)	8.8	8.9	8.7	8.5	8.2	7.8	7.2	7.5	7.7	8.3
- Total	26.5	26.2	26.8	27.6	28.2	28.3	28.0	30.7	33.4	36.5
Light Fuel and Kerosene	4.8	4.8	4.5	4.2	3.9	3.6	3.4	4.1	4.5	5.0
Diesel Fuel Oil	103.1	108.4	109.7	110.4	110.9	111.5	111.8	118.7	128.5	144.9
Heavy Fuel Oil	2.0	1.9	1.7	1.4	1.1	1.0	0.8	0.8	0.9	1.0
Asphalt	21.8	28.7	29.6	30.3	31.3	31.8	31.9	34.6	37.9	42.3
Lubes and Greases	4.4	3.9	3.9	4.0	4.0	4.1	4.1	4.9	5.6	6.3
Petrochemical Feedstock	0.4	7.0	8.3	9.4	10.5	11.1	11.1	11.1	11.1	11.2
Other Products	32.8	33.5	33.8	33.9	34.1	34.1	34.0	35.6	37.8	40.8
Total Oil Products [a]	320.4	345.6	348.4	349.8	351.2	351.3	349.9	363.9	386.7	418.3
Refinery LPG	14.8	13.0	13.0	13.1	13.1	13.1	13.1	13.6	14.4	15.5
Total Products plus Refinery LPG [b]	335.2	358.5	361.5	362.9	364.3	364.4	362.9	377.5	401.1	433.9
	High Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6
Motor Gasoline [a]	124.0	130.5	129.1	127.0	125.5	124.1	122.9	121.5	124.9	127.3
Av. Turbo - Kerosene (Jet A-1)	17.6	17.3	17.8	18.6	19.3	19.7	19.7	20.5	21.2	22.4
- Naphtha (Jet B)	8.8	8.9	8.5	8.3	7.9	7.4	6.8	6.6	6.3	6.6
- Total	26.5	26.2	26.3	26.9	27.2	27.1	26.5	27.0	27.5	29.0
Light Fuel and Kerosene	4.8	4.8	4.7	4.4	4.2	4.0	3.9	4.8	5.2	5.7
Diesel Fuel Oil	103.1	108.4	110.5	111.1	111.8	112.7	113.3	121.7	132.1	147.5
Heavy Fuel Oil	2.0	1.9	1.7	1.4	1.2	1.0	0.8	0.9	0.9	1.0
Asphalt	21.8	28.7	29.6	30.2	30.8	31.4	31.7	34.5	37.4	41.2
Lubes and Greases	4.4	3.9	4.0	4.0	4.1	4.2	4.2	5.0	5.6	6.2
Petrochemical Feedstock	0.4	7.0	8.3	9.4	10.5	11.1	11.1	11.1	11.1	11.2
Other Products	32.8	33.5	33.8	33.9	34.0	34.0	34.0	35.5	37.6	40.2
Total Oil Products [a]	320.4	345.6	348.5	349.0	349.8	350.2	349.1	362.6	383.1	410.0
Refinery LPG	14.8	13.0	16.1	16.2	16.2	16.3	16.3	17.0	18.2	19.6
Total Products plus Refinery LPG [b]	335.2	358.5	364.7	365.2	366.0	366.5	365.4	379.7	401.2	429.6

Note : [a] Excludes Butanes for Blending.
[b] Fuels used to generate electricity exports are not included.

(Petajoules)

British Columbia and Territories

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.2	1.2
Motor Gasoline [a]	129.9	126.8	126.2	125.3	124.7	124.0	123.5	123.9	128.7	133.3
Av. Turbo - Kerosene (Jet A-1)	12.5	14.6	15.3	16.2	16.9	17.4	17.6	19.7	21.8	23.8
- Naphtha (Jet B)	8.2	6.8	6.7	6.5	6.3	6.0	5.5	5.7	5.9	6.4
- Total	20.8	21.4	22.0	22.7	23.2	23.3	23.1	25.4	27.7	30.2
Light Fuel and Kerosene	26.8	26.4	24.0	24.2	24.5	25.0	25.1	23.2	21.4	18.5
Diesel Fuel Oil	97.8	96.0	103.2	104.8	106.4	108.2	109.2	115.0	130.9	154.0
Heavy Fuel Oil	30.5	28.6	30.7	33.6	33.6	31.8	29.8	24.1	20.7	18.7
Asphalt	8.4	9.8	10.1	10.3	10.7	10.8	10.9	11.7	12.8	14.3
Lubes and Greases	3.8	3.6	3.7	3.8	4.0	4.1	4.2	4.8	5.4	6.2
Petrochemical Feedstock	2.3	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.5	2.5
Other Products	18.7	19.7	20.1	20.5	20.7	20.8	20.8	21.3	22.7	24.6
Total Oil Products [a]	340.5	335.8	343.3	348.8	351.4	351.7	350.3	353.2	374.1	403.5
Refinery LPG	6.7	6.7	6.9	7.0	7.0	7.0	7.0	7.1	7.5	8.1
Total Products plus Refinery LPG [b]	347.1	342.5	350.2	355.8	358.4	358.8	357.2	360.3	381.6	411.6

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.3	1.2	1.2
Motor Gasoline [a]	129.9	126.8	125.5	124.1	122.7	121.2	119.6	113.2	110.0	108.0
Av. Turbo - Kerosene (Jet A-1)	12.5	14.6	15.0	15.8	16.3	16.6	16.7	17.3	18.0	18.9
- Naphtha (Jet B)	8.2	6.8	6.6	6.4	6.1	5.7	5.2	5.0	4.8	5.1
- Total	20.8	21.4	21.6	22.1	22.4	22.3	21.9	22.4	22.8	24.0
Light Fuel and Kerosene	26.8	26.4	23.2	22.9	22.6	22.4	21.8	16.9	13.3	10.4
Diesel Fuel Oil	97.8	96.0	102.9	104.5	105.8	106.5	106.5	108.4	119.5	134.8
Heavy Fuel Oil	30.5	28.6	28.6	29.3	26.8	24.7	22.8	17.7	14.9	13.8
Asphalt	8.4	9.8	10.1	10.3	10.5	10.7	10.7	11.6	12.5	13.8
Lubes and Greases	3.8	3.6	3.7	3.7	3.8	3.9	4.0	4.3	4.8	5.2
Petrochemical Feedstock	2.3	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.5	2.5
Other Products	18.7	19.7	19.9	20.1	20.0	20.0	19.9	19.7	20.3	21.3
Total Oil Products [a]	340.5	335.8	338.8	340.4	338.1	335.3	331.0	318.0	321.8	335.0
Refinery LPG	6.7	6.7	6.7	6.8	6.7	6.7	6.6	6.4	6.5	6.9
Total Products plus Refinery LPG [b]	347.1	342.5	345.5	347.2	344.8	342.0	337.6	324.4	328.3	341.8

Note : [a] Excludes Butanes for Blending.
[b] Fuels used to generate electricity exports are not included.

Table A6-16 (Continued)
Total Petroleum Product Demand - Canada and Regions

(Thousands of cubic metres) **Canada**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	177.4	181.7	179.6	177.6	175.6	173.6	171.5	164.1	149.2	149.2
Motor Gasoline [a]	31667.5	31780.5	31538.2	31386.0	31393.8	31524.1	31766.9	33664.5	35539.6	37223.9
Av. Turbo - Kerosene (Jet A-1)	3020.6	3284.1	3443.8	3641.6	3809.7	3915.0	3959.8	4431.6	4905.9	5353.1
- Naphtha (Jet B)	1123.8	1009.0	982.8	962.3	928.8	876.9	811.0	844.0	865.7	944.6
- Total	4144.4	4293.1	4426.7	4603.9	4738.5	4791.9	4770.8	5275.7	5771.6	6297.7
Light Fuel and Kerosene	8899.7	8277.4	8248.5	8149.1	8029.2	7885.8	7698.1	6808.3	6294.0	6400.8
Diesel Fuel Oil	14929.6	15065.4	15817.0	16367.5	16825.4	17238.6	17483.2	19001.8	21221.3	23760.1
Heavy Fuel Oil	7915.9	6949.8	7763.8	8136.5	8238.2	8712.7	7781.4	6692.4	6553.4	8218.4
Asphalt	2376.3	2708.3	2789.6	2859.6	2952.0	2997.0	3012.6	3258.0	3571.6	3989.1
Lubes and Greases	929.2	929.6	961.9	995.5	1030.3	1066.5	1104.0	1273.4	1435.3	1640.6
Petrochemical Feedstock	3485.3	3837.1	3708.7	3331.9	2789.3	2839.1	2870.9	2935.3	2940.9	2949.7
Other Products	5373.4	5813.6	5938.1	6011.5	6052.9	6151.1	6164.0	6480.8	6910.0	7553.2
Total Oil Products [a]	79898.7	79836.3	81372.1	82019.2	82225.2	83380.3	82823.3	85554.3	90386.8	98182.9
Refinery LPG	2400.3	2727.9	2808.1	2907.5	2981.6	3057.0	3083.6	3205.5	3377.0	3636.8
Total Products plus Refinery LPG [b]	82298.9	82564.2	84180.2	84926.7	85206.8	86437.3	85906.9	88759.7	93763.8	101819.6

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	177.4	181.7	179.6	177.6	175.6	173.6	171.5	164.1	149.2	149.2
Motor Gasoline [a]	31667.5	31780.5	31439.1	31147.0	30967.6	30872.8	30807.5	30870.7	31115.5	31446.4
Av. Turbo - Kerosene (Jet A-1)	3020.6	3284.1	3386.8	3549.0	3672.9	3741.5	3755.7	3899.4	4043.3	4262.1
- Naphtha (Jet B)	1123.8	1009.0	966.5	937.8	895.4	838.0	769.2	742.7	713.5	752.1
- Total	4144.4	4293.1	4353.4	4486.8	4568.3	4579.6	4524.9	4642.1	4756.8	5014.1
Light Fuel and Kerosene	8899.7	8277.4	8080.0	7863.5	7609.4	7334.0	7051.6	5388.7	4544.9	4227.4
Diesel Fuel Oil	14929.6	15065.4	15770.0	16211.7	16566.7	16866.0	17026.9	18087.6	19805.5	21605.5
Heavy Fuel Oil	7915.9	6949.8	7600.1	7952.7	7877.6	8290.7	7368.4	5552.9	5403.4	5874.9
Asphalt	2376.3	2708.3	2789.4	2848.0	2904.1	2962.5	2989.2	3249.6	3524.2	3882.4
Lubes and Greases	929.2	929.6	951.5	974.0	996.9	1020.6	1044.6	1163.5	1291.1	1452.4
Petrochemical Feedstock	3485.3	3837.1	3708.1	3330.7	2787.4	2836.5	2867.5	2927.9	2929.7	2932.5
Other Products	5373.4	5813.6	5900.5	5935.6	5926.5	5981.4	5953.5	6026.0	6264.2	6623.0
Total Oil Products [a]	79898.7	79836.3	80771.8	80927.6	80380.2	80917.5	79805.6	78073.0	79784.4	83207.9
Refinery LPG	2400.3	2727.9	2755.3	2840.5	2896.8	2955.0	2969.4	2998.7	3104.2	3259.1
Total Products plus Refinery LPG [b]	82298.9	82564.2	83527.1	83768.2	83277.0	83872.5	82775.0	81071.7	82888.6	86467.0

Note : [a] Excludes Butanes for Blending.
[b] Fuels used to generate electricity exports are not included.

(Thousands of cubic metres) **Atlantic**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	12.1	18.1	17.4	16.7	16.0	15.3	14.6	12.7	10.4	8.9
Motor Gasoline [a]	2751.6	2721.7	2704.6	2689.8	2682.0	2680.8	2687.8	2765.8	2885.5	3033.9
Av. Turbo - Kerosene (Jet A-1)	250.8	250.0	262.1	277.2	290.0	298.0	301.4	337.3	373.4	407.5
- Naphtha (Jet B)	192.9	196.2	191.1	187.1	180.6	170.5	157.7	164.2	168.4	183.7
- Total	443.7	446.2	453.3	464.3	470.6	468.5	459.1	501.5	541.8	591.2
Light Fuel and Kerosene	1852.9	1874.4	1876.2	1890.8	1883.9	1887.8	1892.0	1849.8	1761.7	1865.6
Diesel Fuel Oil	1545.5	1450.2	1569.8	1649.5	1705.2	1742.9	1760.1	1913.0	2191.7	2507.2
Heavy Fuel Oil	2330.1	2889.8	3085.3	3196.6	3444.5	3632.1	3012.4	2438.1	2246.0	2466.4
Asphalt	236.3	271.7	279.9	286.9	296.2	300.8	302.3	327.1	358.6	400.6
Lubes and Greases	65.3	59.0	60.4	61.7	63.2	64.6	66.1	73.3	82.8	94.2
Petrochemical Feedstock	26.0	31.3	31.8	32.7	33.6	34.1	34.1	34.1	34.1	34.1
Other Products	289.9	305.8	313.8	320.7	330.8	338.5	319.2	309.3	315.8	344.4
Total Oil Products [a]	9553.5	10068.2	10392.5	10609.7	10925.9	11165.4	10547.8	10224.8	10428.4	11346.6
Refinery LPG	264.9	266.3	273.3	279.8	286.5	292.1	283.4	283.7	298.8	324.3
Total Products plus Refinery LPG [b]	9818.4	10334.5	10665.7	10889.5	11212.4	11457.5	10831.2	10508.4	10727.2	11670.9

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	12.1	18.1	17.4	16.7	16.0	15.3	14.6	12.7	10.4	8.9
Motor Gasoline [a]	2751.6	2721.7	2699.5	2676.4	2658.2	2644.5	2634.1	2619.8	2669.4	2725.0
Av. Turbo - Kerosene (Jet A-1)	250.8	250.0	257.8	270.1	279.6	284.8	285.9	296.8	307.8	324.4
- Naphtha (Jet B)	192.9	196.2	188.0	182.4	174.1	163.0	149.6	144.4	138.8	146.3
- Total	443.7	446.2	445.8	452.5	453.7	447.8	435.5	441.2	446.5	470.7
Light Fuel and Kerosene	1852.9	1874.4	1865.2	1864.9	1850.5	1851.5	1892.3	1665.6	1592.2	1703.5
Diesel Fuel Oil	1545.5	1450.2	1558.3	1623.1	1669.1	1697.6	1711.1	1811.0	2063.3	2328.3
Heavy Fuel Oil	2330.1	2889.8	3114.6	3298.9	3505.2	3735.8	3211.0	2178.8	2277.1	2600.7
Asphalt	236.3	271.7	279.9	285.8	291.5	297.4	300.1	326.4	354.1	390.2
Lubes and Greases	65.3	59.0	60.1	61.3	62.4	63.6	64.8	70.1	78.1	87.1
Petrochemical Feedstock	26.0	31.3	31.8	32.7	33.6	34.1	34.1	34.1	34.1	34.1
Other Products	289.9	305.8	313.4	321.4	329.0	337.3	321.6	285.9	298.4	325.3
Total Oil Products [a]	9553.5	10068.2	10386.0	10633.6	10869.0	11124.8	10619.1	9445.7	9823.7	10673.9
Refinery LPG	264.9	266.3	246.4	252.0	256.2	260.9	255.2	242.5	258.6	276.7
Total Products plus Refinery LPG [b]	9818.4	10334.5	10632.4	10885.6	11125.3	11385.7	10874.3	9688.2	10082.3	10950.7

Note :[a] Excludes Butanes for Blending.
[b] Fuels used to generate electricity exports are not included.

Table A6-16 (Continued)
Total Petroleum Product Demand - Canada and Regions

(Thousands of cubic metres) **Quebec**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	25.6	26.2	25.8	25.5	25.1	24.7	24.4	22.9	20.4	20.4
Motor Gasoline [a]	6731.0	6709.6	6573.3	6466.5	6406.7	6391.7	6420.3	6831.4	7197.8	7518.5
Av. Turbo - Kerosene (Jet A-1)	712.9	765.5	802.8	848.9	888.1	912.6	923.0	1033.0	1143.6	1247.8
- Naphtha (Jet B)	103.2	78.2	76.1	74.5	71.9	67.9	62.8	65.4	67.1	73.2
- Total	816.1	843.7	878.9	923.4	960.0	980.5	985.9	1098.4	1210.6	1321.0
Light Fuel and Kerosene	3095.5	2709.0	2697.1	2640.9	2560.8	2475.2	2369.9	1909.2	1701.5	1623.1
Diesel Fuel Oil	2414.5	2444.6	2597.3	2725.0	2838.4	2939.1	3003.6	3379.9	3768.1	4026.5
Heavy Fuel Oil	2734.5	1954.2	2163.2	2221.1	2187.4	2588.7	2406.8	2180.7	2164.7	2706.0
Asphalt	586.3	650.7	670.3	687.1	709.4	720.3	724.1	783.3	858.9	959.5
Lubes and Greases	152.5	149.0	153.7	158.6	163.6	168.8	174.1	195.3	217.6	248.5
Petrochemical Feedstock	606.2	473.3	484.7	499.0	513.2	541.7	570.1	627.0	627.0	627.2
Other Products	1526.7	1571.2	1600.4	1618.1	1630.3	1670.9	1672.1	1746.6	1850.3	1995.9
Total Oil Products [a]	18688.8	17531.6	17844.8	17965.2	17994.9	18501.6	18351.2	18774.8	19617.0	21046.5
Refinery LPG	531.8	589.9	609.9	617.7	621.6	652.5	660.4	682.0	711.6	761.9
Total Products plus Refinery LPG [b]	19220.6	18121.5	18454.7	18582.8	18616.5	19154.0	19011.6	19456.8	20328.6	21808.3

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	25.6	26.2	25.8	25.5	25.1	24.7	24.4	22.9	20.4	20.4
Motor Gasoline [a]	6731.0	6709.6	6555.5	6421.9	6321.0	6254.5	6202.3	6136.5	6137.2	6229.2
Av. Turbo - Kerosene (Jet A-1)	712.9	765.5	789.5	827.3	856.2	872.2	875.5	909.0	942.5	993.5
- Naphtha (Jet B)	103.2	78.2	74.9	72.6	69.4	64.9	59.6	57.5	55.3	58.3
- Total	816.1	843.7	864.4	899.9	925.5	937.1	935.1	966.5	997.8	1051.8
Light Fuel and Kerosene	3095.5	2709.0	2650.4	2558.3	2434.8	2304.0	2153.8	1497.8	1167.0	993.3
Diesel Fuel Oil	2414.5	2444.6	2586.8	2692.4	2783.7	2861.9	2908.4	3188.5	3468.3	3597.3
Heavy Fuel Oil	2734.5	1954.2	2101.0	2131.5	2051.5	2378.7	2133.7	1742.4	1614.5	1791.6
Asphalt	586.3	650.7	670.3	684.4	698.0	712.1	718.6	781.7	848.0	934.5
Lubes and Greases	152.5	149.0	152.5	156.1	159.8	163.6	167.4	184.6	203.6	227.9
Petrochemical Feedstock	606.2	473.3	484.7	498.9	513.1	541.6	570.0	626.8	626.8	626.9
Other Products	1526.7	1571.2	1591.0	1601.0	1602.5	1630.9	1619.5	1635.6	1693.0	1784.0
Total Oil Products [a]	18688.8	17531.6	17682.4	17670.1	17515.2	17809.1	17433.3	16783.3	16776.6	17256.8
Refinery LPG	531.8	589.9	572.0	575.7	574.2	597.9	599.9	591.7	597.2	618.0
Total Products plus Refinery LPG [b]	19220.6	18121.5	18254.4	18245.8	18089.4	18407.1	18033.2	17375.0	17373.8	17874.8

Note : [a] Excludes Butanes for Blending.
[b] Fuels used to generate electricity exports are not included.

(Thousands of cubic metres)

Ontario

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	42.3	42.9	42.4	41.9	41.4	41.0	40.5	39.1	35.9	38.9
Motor Gasoline [a]	11515.6	11604.0	11640.0	11741.0	11926.0	12165.3	12442.0	13784.4	14652.6	15342.1
Av. Turbo - Kerosene (Jet A-1)	1096.9	1242.6	1303.1	1377.9	1441.5	1481.4	1498.3	1676.8	1856.3	2025.5
- Naphtha (Jet B)	218.1	179.0	174.4	170.7	164.8	155.6	143.9	149.8	153.6	167.6
- Total	1315.1	1421.7	1477.5	1548.7	1606.3	1637.0	1642.2	1826.6	2009.9	2193.1
Light Fuel and Kerosene	2746.4	2519.6	2567.5	2538.0	2524.8	2475.4	2403.4	2102.0	1937.5	2078.7
Diesel Fuel Oil	3839.0	3856.0	4097.3	4314.1	4497.5	4646.5	4736.1	5193.1	5758.5	6367.8
Heavy Fuel Oil	1936.4	1246.2	1596.1	1748.8	1657.6	1600.3	1539.2	1405.4	1568.4	2524.4
Asphalt	694.7	704.0	725.2	743.4	767.5	779.3	783.4	847.5	929.3	1038.1
Lubes and Greases	415.9	453.1	472.1	491.8	512.4	533.9	556.3	649.5	731.9	838.5
Petrochemical Feedstock	2775.4	3080.0	2899.6	2473.6	1881.7	1882.6	1883.2	1887.3	1891.7	1899.0
Other Products	2178.9	2505.6	2575.6	2612.8	2623.0	2668.5	2700.1	2894.0	3109.2	3442.7
Total Oil Products [a]	27459.5	27432.8	28093.2	28254.0	28038.4	28429.8	28726.4	30628.9	32624.9	35763.4
Refinery LPG	690.9	1021.3	1066.4	1146.8	1207.7	1246.5	1277.2	1353.5	1423.2	1530.3
Total Products plus Refinery LPG [b]	28150.4	28454.2	29159.6	29400.8	29246.1	29676.2	30003.6	31982.4	34048.1	37293.7

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	42.3	42.9	42.4	41.9	41.4	41.0	40.5	39.1	35.9	38.9
Motor Gasoline [a]	11515.6	11604.0	11599.8	11640.9	11729.6	11848.2	11967.7	12401.0	12487.7	12544.9
Av. Turbo - Kerosene (Jet A-1)	1096.9	1242.6	1281.5	1342.9	1389.8	1415.7	1421.1	1475.5	1529.9	1612.7
- Naphtha (Jet B)	218.1	179.0	171.5	166.4	158.9	148.7	136.5	131.8	126.6	133.4
- Total	1315.1	1421.7	1453.0	1509.3	1548.6	1564.4	1557.6	1607.3	1656.5	1746.1
Light Fuel and Kerosene	2746.4	2519.6	2492.2	2410.9	2333.8	2221.5	2087.8	1504.2	1168.4	979.8
Diesel Fuel Oil	3839.0	3856.0	4076.0	4243.1	4377.0	4484.2	4541.3	4822.2	5198.1	5567.3
Heavy Fuel Oil	1936.4	1246.2	1529.0	1665.0	1538.2	1448.9	1356.8	1091.4	1064.9	1082.4
Asphalt	694.7	704.0	725.2	740.5	755.2	770.5	777.5	845.7	917.5	1011.0
Lubes and Greases	415.9	453.1	464.4	475.9	487.8	500.0	512.4	568.4	630.5	716.8
Petrochemical Feedstock	2775.4	3080.0	2899.0	2472.5	1879.9	1880.1	1880.0	1880.1	1880.9	1882.5
Other Products	2178.9	2505.6	2553.3	2565.7	2545.5	2562.5	2565.3	2621.1	2713.7	2852.2
Total Oil Products [a]	27459.5	27432.8	27834.3	27765.8	27237.1	27321.1	27287.0	27380.5	27754.3	28421.9
Refinery LPG	690.9	1021.3	973.9	1048.0	1101.7	1132.0	1154.3	1183.8	1214.3	1256.7
Total Products plus Refinery LPG [b]	28150.4	28454.2	28808.2	28813.7	28338.8	28453.1	28441.3	28564.3	28968.5	29678.6

Note : [a] Excludes Butanes for Blending.
[b] Fuels used to generate electricity exports are not included.

Table A6-16 (Continued)
Total Petroleum Product Demand - Canada and Regions

(Thousands of cubic metres) — Manitoba

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	21.6	20.7	20.7	20.7	20.7	20.6	20.6	19.9	18.2	18.2
Motor Gasoline [a]	1480.0	1466.2	1437.2	1416.5	1404.3	1400.7	1400.5	1486.2	1643.9	1775.3
Av. Turbo - Kerosene (Jet A-1)	114.9	117.6	123.3	130.4	136.4	140.2	141.8	158.7	175.7	191.7
- Naphtha (Jet B)	57.3	54.8	53.3	52.2	50.4	47.6	44.0	45.8	47.0	51.3
- Total	172.2	172.4	176.7	182.6	186.8	187.8	185.8	204.5	222.7	243.0
Light Fuel and Kerosene	141.2	122.2	124.6	117.9	109.6	102.8	97.0	80.6	73.8	78.1
Diesel Fuel Oil	813.5	890.6	907.5	952.2	985.0	1018.0	1041.4	1179.2	1340.2	1499.7
Heavy Fuel Oil	57.4	60.8	68.8	67.2	62.8	58.9	55.1	45.9	39.8	33.5
Asphalt	49.4	49.5	51.0	52.3	53.9	54.8	55.1	59.6	65.3	73.0
Lubes and Greases	35.5	33.3	34.5	35.8	37.2	38.5	40.0	46.8	53.0	60.8
Petrochemical Feedstock	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Products	8.9	9.8	10.1	10.6	11.0	11.4	11.7	13.8	15.6	17.9
Total Oil Products [a]	2780.2	2825.4	2831.1	2855.9	2871.4	2893.5	2907.1	3136.5	3472.5	3799.5
Refinery LPG	12.5	17.6	17.7	17.9	18.0	18.1	18.2	19.7	21.8	23.8
Total Products plus Refinery LPG [b]	2792.8	2843.1	2848.8	2873.8	2889.3	2911.7	2925.3	3156.2	3494.3	3823.3

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	21.6	20.7	20.7	20.7	20.7	20.6	20.6	19.9	18.2	18.2
Motor Gasoline [a]	1480.0	1466.2	1433.7	1410.2	1391.1	1377.3	1365.0	1367.9	1434.4	1489.1
Av. Turbo - Kerosene (Jet A-1)	114.9	117.6	121.3	127.1	131.5	134.0	134.5	139.6	144.8	152.6
- Naphtha (Jet B)	57.3	54.8	52.5	50.9	48.6	45.5	41.7	40.3	38.7	40.8
- Total	172.2	172.4	173.7	178.0	180.1	179.5	176.2	180.0	183.5	193.4
Light Fuel and Kerosene	141.2	122.2	115.9	107.5	96.9	87.0	77.2	37.0	38.1	42.7
Diesel Fuel Oil	813.5	890.6	901.3	936.7	961.6	987.7	1005.7	1114.1	1243.7	1359.1
Heavy Fuel Oil	57.4	60.8	63.8	62.0	58.5	55.5	52.6	47.1	40.4	30.4
Asphalt	49.4	49.5	51.0	52.0	53.1	54.2	54.7	59.4	64.5	71.1
Lubes and Greases	35.5	33.3	34.2	35.1	36.0	37.0	38.0	43.8	48.9	54.8
Petrochemical Feedstock	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Products	8.9	9.8	10.1	10.4	10.7	11.0	11.3	13.1	14.7	16.7
Total Oil Products [a]	2780.2	2825.4	2804.4	2812.7	2808.8	2809.8	2801.3	2882.2	3086.3	3275.5
Refinery LPG	12.5	17.6	13.2	13.2	13.2	13.2	13.2	13.6	14.6	15.5
Total Products plus Refinery LPG [b]	2792.8	2843.1	2817.6	2825.9	2822.0	2823.0	2814.5	2895.8	3100.9	3291.1

Note : [a] Excludes Butanes for Blending.
[b] Fuels used to generate electricity exports are not included.

(Thousands of cubic metres) **Saskatchewan**

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	11.8	11.2	11.1	10.9	10.8	10.6	10.5	9.9	8.9	7.5
Motor Gasoline [a]	1862.9	1853.7	1810.1	1764.3	1725.9	1697.3	1675.4	1680.6	1799.0	1963.0
Av. Turbo - Kerosene (Jet A-1)	4.7	22.4	23.5	24.8	26.0	26.7	27.0	30.2	33.5	36.5
- Naphtha (Jet B)	78.2	62.0	60.3	59.1	57.0	53.8	49.8	51.8	53.2	58.0
- Total	82.9	84.4	83.8	83.9	83.0	80.5	76.8	82.0	86.6	94.5
Light Fuel and Kerosene	243.3	241.6	241.8	223.9	212.1	202.9	195.6	157.7	146.1	144.8
Diesel Fuel Oil	1124.4	1139.5	1139.9	1162.9	1181.7	1209.6	1228.1	1295.6	1456.6	1631.9
Heavy Fuel Oil	76.9	66.4	74.7	64.6	52.6	46.1	35.1	24.2	15.9	17.0
Asphalt	130.1	166.4	171.4	175.8	181.5	184.2	185.2	200.4	219.7	245.4
Lubes and Greases	49.4	43.4	45.4	47.4	49.5	51.8	54.1	60.0	69.6	79.1
Petrochemical Feedstock	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Products	132.8	142.7	142.8	142.7	142.8	143.5	144.0	149.9	162.6	177.9
Total Oil Products [a]	3715.7	3749.3	3720.9	3676.4	3639.9	3626.6	3604.8	3660.4	3965.0	4361.0
Refinery LPG	110.6	108.0	107.2	106.2	105.4	105.2	104.8	106.5	115.4	126.7
Total Products plus Refinery LPG [b]	3826.3	3857.3	3828.1	3782.6	3745.3	3731.8	3709.5	3766.8	4080.4	4487.7

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	11.8	11.2	11.1	10.9	10.8	10.6	10.5	9.9	8.9	7.5
Motor Gasoline [a]	1862.9	1853.7	1804.8	1753.6	1708.5	1671.7	1641.0	1575.7	1607.2	1671.3
Av. Turbo - Kerosene (Jet A-1)	4.7	22.4	23.1	24.2	25.0	25.5	25.6	26.6	27.6	29.1
- Naphtha (Jet B)	78.2	62.0	59.3	57.6	55.0	51.5	47.2	45.6	43.8	46.2
- Total	82.9	84.4	82.4	81.8	80.0	77.0	72.8	72.2	71.4	75.2
Light Fuel and Kerosene	243.3	241.6	232.8	212.9	198.1	185.4	174.2	120.2	97.9	88.3
Diesel Fuel Oil	1124.4	1139.5	1132.1	1142.0	1150.8	1167.8	1176.5	1201.7	1328.8	1457.4
Heavy Fuel Oil	76.9	66.4	66.7	60.8	55.4	54.3	47.7	48.7	26.4	15.9
Asphalt	130.1	166.4	171.4	175.1	178.5	182.2	183.8	200.0	216.9	239.0
Lubes and Greases	49.4	43.4	45.1	46.8	48.6	50.4	52.3	57.8	65.7	73.2
Petrochemical Feedstock	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Products	132.8	142.7	141.9	141.4	141.0	141.3	141.3	144.2	152.9	163.7
Total Oil Products [a]	3715.7	3749.3	3688.5	3625.2	3571.7	3540.7	3500.1	3430.4	3576.1	3791.5
Refinery LPG	110.6	108.0	106.8	105.4	104.3	103.9	103.1	102.2	107.7	115.2
Total Products plus Refinery LPG[b]	3826.3	3857.3	3795.3	3730.7	3676.0	3644.6	3603.2	3532.6	3683.8	3906.7

Note : [a] Excludes Butanes for Blending.
[b] Fuels used to generate electricity exports are not included.

Table A6-16 (Continued)
Total Petroleum Product Demand - Canada and Regions

(Thousands of cubic metres)

Alberta

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	22.9	20.5	20.4	20.2	20.1	20.0	19.9	19.8	18.6	18.6
Motor Gasoline [a]	3577.9	3765.5	3733.0	3691.5	3650.8	3609.4	3578.5	3541.7	3647.1	3744.8
Av. Turbo - Kerosene (Jet A-1)	491.1	480.1	503.5	532.4	557.0	572.4	578.9	647.9	717.3	782.7
- Naphtha (Jet B)	245.7	248.2	241.8	236.7	228.5	215.7	199.5	207.7	213.0	232.4
- Total	736.8	728.4	745.3	769.2	785.5	788.1	778.5	855.6	930.3	1015.1
Light Fuel and Kerosene	124.1	124.3	118.7	108.8	100.8	93.7	89.5	106.7	116.7	129.1
Diesel Fuel Oil	2664.2	2802.2	2837.3	2854.0	2867.1	2883.9	2890.9	3068.6	3321.6	3745.0
Heavy Fuel Oil	48.4	46.2	40.6	32.8	27.3	24.2	18.7	20.1	21.3	23.1
Asphalt	490.9	645.6	665.0	681.7	703.8	714.6	718.4	777.2	852.1	951.9
Lubes and Greases	113.1	99.9	100.9	101.9	102.9	103.9	105.0	125.8	142.3	161.0
Petrochemical Feedstock	10.1	198.5	235.6	266.9	298.3	315.3	315.2	315.9	316.9	318.4
Other Products	784.9	804.1	810.4	813.8	817.4	818.3	816.5	853.5	908.3	981.0
Total Oil Products [a]	8573.4	9235.1	9307.1	9340.8	9373.9	9371.4	9331.0	9684.7	10275.3	11088.0
Refinery LPG	544.0	477.5	480.9	482.4	483.9	483.7	481.6	499.9	530.5	572.4
Total Products plus Refinery LPG [b]	9117.3	9712.6	9788.0	9823.2	9857.8	9855.0	9812.6	10184.6	10805.9	11660.3

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	22.9	20.5	20.4	20.2	20.1	20.0	19.9	19.8	18.6	18.6
Motor Gasoline [a]	3577.9	3765.5	3723.5	3664.1	3620.2	3580.1	3545.7	3504.8	3604.6	3671.5
Av. Turbo - Kerosene (Jet A-1)	491.1	480.1	495.2	518.9	537.0	547.0	549.1	570.1	591.2	623.1
- Naphtha (Jet B)	245.7	248.2	237.8	230.7	220.3	206.2	189.2	182.7	175.5	185.0
- Total	736.8	728.4	733.0	749.6	757.3	753.2	738.3	752.8	766.7	808.2
Light Fuel and Kerosene	124.1	124.3	121.6	114.8	108.8	104.0	101.2	124.0	136.7	149.6
Diesel Fuel Oil	2664.2	2802.2	2856.2	2873.1	2889.4	2913.0	2930.3	3146.6	3414.2	3812.1
Heavy Fuel Oil	48.4	46.2	40.8	33.0	27.6	24.6	19.2	21.0	22.4	24.1
Asphalt	490.9	645.6	665.0	679.0	692.5	706.5	713.0	775.6	841.3	927.1
Lubes and Greases	113.1	99.9	101.5	103.1	104.7	106.4	108.1	128.3	142.4	158.7
Petrochemical Feedstock	10.1	198.5	235.6	266.9	298.2	315.3	315.2	315.8	316.7	318.0
Other Products	784.9	804.1	810.8	812.4	814.9	816.7	815.8	852.3	902.7	966.3
Total Oil Products [a]	8573.4	9235.1	9308.3	9316.2	9333.8	9339.9	9306.6	9640.9	10166.4	10854.2
Refinery LPG	544.0	477.5	594.6	596.2	598.5	600.2	599.5	628.5	670.7	724.2
Total Products plus Refinery LPG [b]	9117.3	9712.6	9902.9	9912.5	9932.2	9940.1	9906.1	10269.4	10837.1	11578.4

Note :[a]Excludes Butanes for Blending.
[b] Fuels used to generate electricity exports are not included.

(Thousands of cubic metres)

British Columbia and Territories

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	41.1	42.0	41.9	41.7	41.5	41.4	41.2	39.8	36.5	36.5
Motor Gasoline [a]	3748.5	3659.8	3640.0	3616.5	3598.2	3579.0	3562.4	3574.3	3713.7	3846.5
Av. Turbo - Kerosene (Jet A-1)	349.2	405.8	425.5	450.0	470.7	483.7	489.3	547.6	606.2	661.4
- Naphtha (Jet B)	228.4	190.6	185.7	181.8	175.5	165.7	153.2	159.5	163.5	178.5
- Total	577.6	596.4	611.2	631.7	646.2	649.4	642.5	707.0	769.7	839.9
Light Fuel and Kerosene	696.2	686.3	622.6	628.9	637.1	648.1	650.8	602.3	556.8	481.5
Diesel Fuel Oil	2528.7	2482.3	2668.0	2709.9	2750.5	2798.6	2823.0	2972.4	3384.6	3981.9
Heavy Fuel Oil	732.0	686.2	735.1	805.4	806.0	762.3	714.1	578.0	497.2	448.0
Asphalt	188.5	220.4	226.9	232.5	239.6	243.0	244.1	262.9	287.7	320.7
Lubes and Greases	97.3	92.0	95.1	98.2	101.5	104.9	108.4	122.7	138.1	158.5
Petrochemical Feedstock	65.9	54.0	56.9	59.7	62.6	65.4	68.2	71.1	71.1	71.1
Other Products	451.3	474.4	484.9	492.8	497.6	500.0	500.4	513.8	548.3	593.4
Total Oil Products [a]	9127.1	8993.9	9182.5	9317.3	9380.8	9392.1	9355.1	9444.3	10003.7	10778.0
Refinery LPG	245.5	247.2	252.7	256.8	258.7	259.0	257.9	260.3	275.8	297.4
Total Products plus Refinery LPG [b]	9372.6	9241.2	9435.3	9574.1	9639.5	9651.1	9613.0	9704.6	10279.5	11075.4

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Aviation Gasoline	41.1	42.0	41.9	41.7	41.5	41.4	41.2	39.8	36.5	36.5
Motor Gasoline [a]	3748.5	3659.8	3622.3	3579.8	3539.0	3496.6	3451.7	3265.1	3175.1	3115.4
Av. Turbo - Kerosene (Jet A-1)	349.2	405.8	418.5	438.5	453.8	462.3	464.1	481.8	499.6	526.6
- Naphtha (Jet B)	228.4	190.6	182.6	177.2	169.2	158.3	145.3	140.3	134.8	142.1
- Total	577.6	596.4	601.1	615.7	623.0	620.6	609.4	622.1	634.4	668.7
Light Fuel and Kerosene	696.2	686.3	602.0	594.2	586.6	580.7	565.0	439.9	344.7	270.2
Diesel Fuel Oil	2528.7	2482.3	2659.3	2701.3	2735.2	2753.8	2753.6	2803.6	3089.1	3484.1
Heavy Fuel Oil	732.0	686.2	684.2	701.5	641.1	592.9	547.3	423.4	357.7	329.8
Asphalt	188.5	220.4	226.7	231.2	235.4	239.7	241.5	260.8	281.8	309.6
Lubes and Greases	97.3	92.0	93.8	95.7	97.6	99.6	101.5	110.5	121.9	134.0
Petrochemical Feedstock	65.9	54.0	56.9	59.7	62.6	65.4	68.2	71.1	71.1	71.1
Other Products	451.3	474.4	480.0	483.4	482.8	481.6	478.7	473.9	488.8	514.8
Total Oil Products [a]	9127.1	8993.9	9068.1	9104.2	9044.7	8972.2	8858.2	8510.0	8601.1	8934.1
Refinery LPG	245.5	247.2	248.4	249.9	248.6	247.0	244.2	236.4	241.1	252.7
Total Products plus Refinery LPG [b]	9372.6	9241.2	9316.5	9354.1	9293.3	9219.2	9102.4	8746.4	8842.1	9186.7

Note : [a] Excludes Butanes for Blending.
[b] Fuels used to generate electricity exports are not included.

Table A6-17
Refinery Feedstock Requirements - Canada and Regions

(Thousands of cubic metres) — Canada

Low Price Case

Total Refined Petroleum Products	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Domestic Demand [a]	78323	77875	78169	78787	78994	80099	79546	82139	86775	94240
Deduct Product Imports	-5285	-5000	-7969	-7929	-8007	-8802	-8286	-10518	-13795	-19263
Add Product Exports	8093	9366	8289	8814	8814	8814	8814	8814	8694	8694
Net Regional Transfers -In/+Out	0	1	0	0	0	0	0	0	0	0
Inventory +Build/-Draw	-3076	-6359	-1473	-85	130	-155	300	530	953	0
Add Product Losses, Own Use and Other	7567	8447	6012	6139	6212	6340	6361	6620	6986	7579
Refinery Feedstock Requirements	85622	84330	83028	85726	86143	86296	86735	87585	89613	91250
Deduct Partially Processed Oil and Other Material	-1721	-2397	-2353	-2337	-2339	-2373	-2410	-1643	-1646	-1643
Deduct Gas Plant Butanes supplied to Refineries	-1011	-1022	-1059	-1059	-1061	-1059	-1059	-1096	-1132	-1132
Refinery Requirements for Crude Oil & Equivalent	82890	80911	79616	82330	82743	82864	83266	84846	86835	88475
Per Day	226.5	221.7	218.1	225.6	226.1	227.0	228.1	232.5	237.3	242.4
Crude Oil and Equivalent Supply (thousands of cubic metres per day)										
Domestic: Heavy	13.5	15.2	16.2	16.8	17.0	17.3	17.5	16.5	17.7	19.0
Light & Medium	180.5	163.2	155.1	160.3	160.5	161.2	162.0	122.6	100.3	81.0
Imports	33.0	42.9	47.6	48.1	48.6	48.6	48.6	93.3	119.2	142.4
Inventory Change	-0.5	0.4	-0.8	0.4	0.0	-0.1	0.0	0.1	0.1	0.0
Total	226.5	221.7	218.1	225.6	226.1	227.0	228.1	232.5	237.3	242.4

High Price Case

Total Refined Petroleum Products	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Domestic Demand [a]	78323	77875	77556	77706	77195	77710	76636	74964	76633	79943
Deduct Product Imports	-5285	-5000	-8096	-8068	-7381	-7630	-6600	-5978	-6549	-8240
Add Product Exports	8093	9366	8517	9050	9215	9205	9202	8811	8904	8878
Net Regional Transfers -In/+Out	0	0	0	0	0	0	0	0	0	0
Inventory +Build/-Draw	-3076	-6359	-2047	-168	67	-203	-162	201	466	0
Add Product Losses, Own Use and Other	7567	8447	5971	6061	6082	6163	6141	6107	6254	6512
Refinery Feedstock Requirements	85622	84329	81901	84581	85178	85245	85217	84105	85708	87093
Deduct Partially Processed Oil and Other Material	-1721	-2397	-2353	-2337	-2339	-2373	-2410	-1643	-1646	-1643
Deduct Gas Plant Butanes supplied to Refineries	-1011	-1022	-1059	-1059	-1061	-1059	-1059	-1096	-1132	-1132
Refinery Requirements for Crude Oil & Equivalent	82890	80910	78489	81185	81778	81813	81748	81366	82930	84318
Per Day	226.5	221.7	215.0	222.4	223.4	224.1	224.0	222.9	226.6	231.0
Crude Oil and Equivalent Supply (thousands of cubic metres per day)										
Domestic: Heavy	13.5	15.2	16.2	16.8	17.0	17.3	17.5	16.5	17.7	19.0
Light & Medium	180.5	163.2	152.4	158.1	158.4	158.8	158.5	132.5	149.8	128.2
Imports	33.0	42.9	46.5	47.5	48.0	48.0	48.0	73.8	59.1	83.8
Inventory Change	-0.4	0.4	-0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0
Total	226.6	221.7	215.0	222.4	223.4	224.1	224.0	222.9	226.6	231.0

Note: 1984 & 1985 based on Stats. Canada Catalogue 45-004.
Domestic demand plus product losses, own use and other corresponds to total products plus refinery LPG in Table A6-16 for 1986 to 2005.
[a] Domestic demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Table A6-17 (Continued)
Refinery Feedstock Requirements - Canada and Regions

(Thousands of cubic metres)

Atlantic

Low Price Case

Total Refined Petroleum Products	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Domestic Demand [a]	9382	9310	10148	10359	10667	10901	10299	9985	10184	11081
Deduct Product Imports	-2021	-1857	-2389	-2720	-2880	-3053	-2469	-2219	-2147	-2615
Add Product Exports	624	997	860	1130	1130	1130	1130	1130	1130	1130
Net Regional Transfers -In/+Out	-215	-7	22	22	22	22	22	36	36	36
Inventory +Build/-Draw	-80	-473	-33	-14	33	-67	-23	37	140	0
Add Product Losses, Own Use and Other	499	558	518	530	545	556	532	522	541	589
Refinery Feedstock Requirements	8140	8528	9125	9308	9517	9489	9491	9491	9884	10221
Deduct Partially Processed Oil and Other Material	-23	-11								
Deduct Gas Plant Butanes supplied to Refineries										
Refinery Requirements for Crude Oil & Equivalent	8117	8517	9125	9308	9517	9489	9491	9491	9884	10221
Per Day	22.2	23.3	25.0	25.5	26.0	26.0	26.0	26.0	27.0	28.0
Crude Oil and Equivalent Supply (thousands of cubic metres per day)										
Domestic: Heavy	0.2	0.2								
Light & Medium	8.7	2.3								
Imports	13.6	21.2	25.0	25.5	26.0	26.0	26.0	26.0	27.0	28.0
Inventory Change	-0.3	-0.4								
Total	22.2	23.3	25.0	25.5	26.0	26.0	26.0	26.0	27.0	28.0

High Price Case

Total Refined Petroleum Products	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Domestic Demand [a]	9382	9310	10115	10354	10582	10830	10338	9194	9558	10381
Deduct Product Imports	-2021	-1857	-2976	-3299	-3388	-3551	-2996	-2612	-2725	-3240
Add Product Exports	624	997	832	1130	1130	1130	1130	1130	1130	1130
Net Regional Transfers -In/+Out	-215	-7	276	396	396	396	396	396	396	396
Inventory +Build/-Draw	-80	-473	-42	-24	33	-52	-134	49	123	
Add Product Losses, Own Use and Other	499	558	518	531	543	556	536	493	522	568
Refinery Feedstock Requirements	8140	8528	8723	9088	9296	9309	9270	8650	9004	9235
Deduct Partially Processed Oil and Other Material	-23	-11								
Deduct Gas Plant Butanes supplied to Refineries										
Refinery Requirements for Crude Oil & Equivalent	8117	8517	8723	9088	9296	9309	9270	8650	9004	9235
Per Day	22.2	23.3	23.9	24.9	25.4	25.5	25.4	23.7	24.6	25.3
Crude Oil and Equivalent Supply (thousands of cubic metres per day)										
Domestic: Heavy	0.2	0.2								
Light & Medium	8.7	2.3						3.5	17.5	17.5
Imports	13.6	21.2	23.9	24.9	25.4	25.4	25.4	20.2	7.1	7.8
Inventory Change	-0.3	-0.4				0.1				
Total	22.2	23.3	23.9	24.9	25.4	25.5	25.4	23.7	24.6	25.3

Note: 1984 & 1985 based on Stats. Canada Catalogue 45-004.
Domestic demand plus product losses, own use and other corresponds to total products plus refinery LPG in Table A6-16 for 1986 to 2005.
[a] Domestic demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Table A6-17 (Continued)
Refinery Feedstock Requirements - Canada and Regions

(Thousands of cubic metres) **Quebec**

Low Price Case

Total Refined Petroleum Products	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Domestic Demand [a]	18233	17075	17191	17306	17334	17821	17677	18087	18898	20273
Deduct Product Imports	-2531	-2362	-4512	-3907	-4076	-4572	-4501	-4135	-5047	-6360
Add Product Exports	1337	1414	1207	984	984	984	984	984	984	984
Net Regional Transfers -In/+Out	661	656	1119	1119	1239	1239	1239	357	357	357
Inventory +Build/-Draw	-653	-1306	521	12	71	-14	55	27	214	0
Add Product Losses, Own Use and Other	1457	2076	1264	1277	1282	1333	1335	1370	1430	1535
Refinery Feedstock Requirements	18504	17553	16790	16791	16834	16791	16789	16690	16836	16789
Deduct Partially Processed Oil and Other Material	-481	-1029	-986	-986	-988	-986	-986	-183	-183	-183
Deduct Gas Plant Butanes supplied to Refineries										
Refinery Requirements for Crude Oil & Equivalent	18023	16504	15804	15805	15846	15805	15803	16507	16653	16606
Per Day	49.2	45.2	43.3	43.3	43.3	43.3	43.3	45.2	45.5	45.5
Crude Oil and Equivalent Supply (thousands of cubic metres per day)										
Domestic: Heavy	2.1	1.7	1.8	1.8	1.9	1.9	2.0			
Light & Medium	29.1	21.7	18.8	18.8	18.7	18.7	18.6			
Imports	19.2	21.3	22.6	22.6	22.6	22.6	22.6	45.5	45.5	45.5
Inventory Change	-1.2	0.5	0.1	0.1	0.1	0.1	0.1	-0.3		
Total	49.2	45.2	43.3	43.3	43.3	43.3	43.3	45.2	45.5	45.5

High Price Case

Total Refined Petroleum Products	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Domestic Demand [a]	18233	17075	17001	16989	16840	17121	16761	16137	16130	16581
Deduct Product Imports	-2531	-2362	-3783	-3420	-3277	-3558	-3157	-2573	-2598	-3064
Add Product Exports	1337	1414	1207	984	984	984	984	984	984	984
Net Regional Transfers -In/+Out	661	656	713	630	630	630	630	630	630	630
Inventory +Build/-Draw	-653	-1306	33	-15	43	-39	-65	10	78	
Add Product Losses, Own Use and Other	1457	2076	1253	1257	1249	1286	1273	1238	1243	1284
Refinery Feedstock Requirements	18504	17553	16424	16425	16469	16424	16426	16426	16467	16415
Deduct Partially Processed Oil and Other Material	-481	-1029	-986	-986	-988	-986	-986	-183	-183	-183
Deduct Gas Plant Butanes supplied to Refineries										
Refinery Requirements for Crude Oil & Equivalent	18023	16504	15438	15439	15481	15438	15440	16243	16284	16232
Per Day	49.2	45.2	42.3	42.3	42.3	42.3	42.3	44.5	44.5	44.5
Crude Oil and Equivalent Supply (thousands of cubic metres per day)										
Domestic: Heavy	2.1	1.7	1.8	1.8	1.9	1.9	2.0			
Light & Medium	29.1	21.7	17.9	17.9	17.8	17.8	17.7			
Imports	19.2	21.3	22.6	22.6	22.6	22.6	22.6	44.5	44.5	44.5
Inventory Change	-1.2	0.5								
Total	49.2	45.2	42.3	42.3	42.3	42.3	42.3	44.5	44.5	44.5

Note: 1984 & 1985 based on Stats. Canada Catalogue 45-004.
Domestic demand plus product losses, own use and other corresponds to total products plus refinery LPG in Table A6-16 for 1986 to 2005.
[a] Domestic demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

(Thousands of cubic metres) **Ontario**

Low Price Case

Total Refined Petroleum Products	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Domestic Demand [a]	25940	26337	26223	26370	26167	26533	26811	28590	30452	33372
Deduct Product Imports	-544	-661	-1068	-1302	-1051	-1177	-1316	-4064	-6201	-9188
Add Product Exports	4238	4425	4031	4302	4302	4302	4302	4302	4302	4302
Net Regional Transfers -In/+Out	-985	-1219	-1676	-1676	-1796	-1796	-1796	-1018	-1018	-1018
Inventory +Build/-Draw	-1493	-2658	-882	-65	41	20	160	185	345	0
Add Product Losses, Own Use and Other	3224	3096	2937	3031	3079	3144	3193	3392	3596	3922
Refinery Feedstock Requirements	30380	29320	29565	30660	30742	31026	31354	31387	31476	31390
Deduct Partially Processed Oil and Other Material	-904	-833	-840	-840	-840	-876	-913	-949	-952	-949
Deduct Gas Plant Butanes supplied to Refineries	-101	-61	-110	-110	-110	-110	-110	-110	-146	-146
Refinery Requirements for Crude Oil & Equivalent	29375	28426	28615	29710	29792	30040	30331	30328	30378	30295
Per Day	80.3	77.9	78.4	81.4	81.4	82.3	83.1	83.1	83.0	83.0
Crude Oil and Equivalent Supply (thousands of cubic metres per day)										
Domestic: Heavy	7.3	8.6	9.3	9.5	9.6	9.7	9.7	10.2	10.7	11.3
Light & Medium	71.8	68.1	69.9	72.1	71.9	72.7	73.4	51.1	25.6	2.8
Imports	0.2	0.4						21.8	46.7	68.9
Inventory Change	1.0	0.8	-0.8	-0.2	-0.1	-0.1				
Total	80.3	77.9	78.4	81.4	81.4	82.3	83.1	83.1	83.0	83.0

High Price Case

Total Refined Petroleum Products	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Domestic Demand [a]	25940	26337	25895	25827	25334	25413	25382	25470	25815	26432
Deduct Product Imports	-544	-661	-1337	-1349	-716	-521	-447	-793	-1226	-1936
Add Product Exports	4238	4425	4032	4309	4309	4302	4302	4265	4294	4301
Net Regional Transfers -In/+Out	-985	-1219	-1432	-1384	-1386	-1384	-1383	-1384	-1384	-1384
Inventory +Build/-Draw	-1493	-2658	-948	-95	14	-11		43	92	
Add Product Losses, Own Use and Other	3224	3096	2914	2986	3005	3040	3060	3094	3154	3247
Refinery Feedstock Requirements	30380	29320	29124	30294	30560	30839	30914	30695	30745	30660
Deduct Partially Processed Oil and Other Material	-904	-833	-840	-840	-840	-876	-913	-949	-952	-949
Deduct Gas Plant Butanes supplied to Refineries	-101	-61	-110	-110	-110	-110	-110	-110	-146	-146
Refinery Requirements for Crude Oil & Equivalent	29375	28426	28174	29344	29610	29853	29891	29636	29647	29565
Per Day	80.3	77.9	77.2	80.4	80.9	81.8	81.9	81.2	81.0	81.0
Crude Oil and Equivalent Supply (thousands of cubic metres per day)										
Domestic: Heavy	7.3	8.6	9.3	9.5	9.6	9.7	9.7	10.2	10.7	11.3
Light & Medium	71.8	68.1	67.9	70.9	71.3	72.1	72.3	61.8	62.8	38.2
Imports	0.2	0.4					0.0	9.1	7.5	31.5
Inventory Change	1.0	0.8					-0.1	0.1		
Total	80.3	77.9	77.2	80.4	80.9	81.8	81.9	81.2	81.0	81.0

Note: 1984 & 1985 based on Stats. Canada Catalogue 45-004.
Domestic demand plus product losses, own use and other corresponds to total products plus refinery LPG in Table A6-16 for 1986 to 2005.
[a] Domestic Demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Table A6-17 (Continued)
Refinery Feedstock Requirements - Canada and Regions

(Thousands of cubic metres) — **Prairies & NWT**

Low Price Case

Total Refined Petroleum Products	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Domestic Demand [a]	16277	16754	15606	15619	15630	15637	15589	16219	17435	18949
Deduct Product Imports	-6	-6								
Add Product Exports	997	1089	1067	1000	1000	1000	1000	1000	1000	1000
Net Regional Transfers -In/+Out	1867	2180	2869	2968	2968	2968	3078	3201	3248	3300
Inventory +Build/-Draw	-901	-1729	-866	-15	-11	-45	85	128	177	
Add Product Losses, Own Use and Other	1877	2149	859	860	862	862	858	889	946	1023
Refinery Feedstock Requirements	20110	20437	19535	20432	20449	20422	20610	21437	22806	24272
Deduct Partially Processed Oil and Other Material	-94	-133	-162	-146	-146	-146	-146	-146	-146	-146
Deduct Gas Plant Butanes supplied to Refineries	-854	-903	-876	-876	-878	-876	-876	-913	-913	-913
Refinery Requirements for Crude Oil & Equivalent	19162	19401	18497	19410	19425	19400	19588	20378	21747	23213
Per Day	52.4	53.2	50.7	53.2	53.1	53.2	53.7	55.8	59.4	63.6
Crude Oil and Equivalent Supply (thousands of cubic metres per day)										
Domestic: Heavy	3.9	4.7	5.1	5.5	5.5	5.7	5.8	6.3	7.0	7.7
Light & Medium	48.5	48.5	45.6	47.2	47.6	47.5	47.9	49.5	52.4	55.9
Imports										
Inventory Change	0.0	0.0		0.5						
Total	52.4	53.2	50.7	53.2	53.1	53.2	53.7	55.8	59.4	63.6

High Price Case

Total Refined Petroleum Products	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Domestic Demand [a]	16277	16754	15657	15612	15573	15551	15470	15819	16695	17787
Deduct Product Imports	-6	-6								
Add Product Exports	997	1089	1284	1229	1245	1243	1240	1247	1264	1286
Net Regional Transfers -In/+Out	1867	2180	1747	2154	2220	2128	2048	1834	1980	2253
Inventory +Build/-Draw	-901	-1729	-858	-21	-12	-47	52	87	132	
Add Product Losses, Own Use and Other	1877	2149	858	857	857	857	853	879	927	989
Refinery Feedstock Requirements	20110	20437	18688	19831	19883	19732	19663	19866	20998	22315
Deduct Partially Processed Oil and Other Material	-94	-133	-162	-146	-146	-146	-146	-146	-146	-146
Deduct Gas Plant Butanes supplied to Refineries	-854	-903	-876	-876	-878	-876	-876	-913	-913	-913
Refinery Requirements for Crude Oil & Equivalent	19162	19401	17650	18809	18859	18710	18641	18807	19939	21256
Per Day	52.4	53.2	48.4	51.5	51.5	51.3	51.1	51.5	54.5	58.2
Crude Oil and Equivalent Supply (thousands of cubic metres per day)										
Domestic: Heavy	3.9	4.7	5.1	5.5	5.5	5.7	5.8	6.3	7.0	7.7
Light & Medium	48.5	48.5	43.3	46.0	46.0	45.6	45.2	45.2	47.5	50.5
Imports										
Inventory Change	0.0	0.0					0.1			
Total	52.4	53.2	48.4	51.5	51.5	51.3	51.1	51.5	54.5	58.2

Note: 1984 & 1985 based on Stats. Canada Catalogue 45-004.
Domestic demand plus product losses, own use and other corresponds to total products plus refinery LPG in Table A6-16 for 1986 to 2005.
[a] Domestic demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Table A6-17 (Continued)
Refinery Feedstock Requirements - Canada and Regions

(Thousands of cubic metres) **British Columbia and Yukon**

Low Price Case

Total Refined Petroleum Products	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Domestic Demand [a]	8491	8399	9001	9133	9196	9207	9170	9258	9806	10565
Deduct Product Imports	-183	-114						-100	-400	-1100
Add Product Exports	897	1441	1124	1398	1398	1398	1398	1398	1278	1278
Net Regional Transfers -In/+Out	-1324	-1609	-2335	-2434	-2434	-2434	-2544	-2578	-2625	-2677
Inventory +Build/-Draw	51	-193	-212	-3	-4	-49	23	54	77	
Add Product Losses, Own Use and Other	510	568	434	441	444	445	443	447	473	510
Refinery Feedstock Requirements	8448	8492	8012	8535	8600	8567	8490	8479	8609	8576
Deduct Partially Processed Oil and Other Material	-219	-391	-365	-365	-365	-365	-365	-365	-365	-365
Deduct Gas Plant Butanes supplied to Refineries	-56	-58	-73	-73	-73	-73	-73	-73	-73	-73
Refinery Requirements for Crude Oil & Equivalent	8173	8043	7574	8097	8162	8129	8052	8041	8171	8138
Per Day	22.3	22.0	20.8	22.2	22.3	22.3	22.1	22.0	22.3	22.3
Crude Oil and Equivalent Supply (thousands of cubic metres per day)										
Domestic: Heavy										
Light & Medium	22.4	22.6	20.8	22.2	22.3	22.3	22.1	22.0	22.3	22.3
Imports										
Inventory Change	-0.1	-0.6								
Total	22.3	22.0	20.8	22.2	22.3	22.3	22.1	22.0	22.3	22.3

High Price Case

Total Refined Petroleum Products	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Domestic Demand [[a]	8491	8399	8888	8924	8866	8795	8685	8344	8435	8762
Deduct Product Imports	-183	-114								
Add Product Exports	897	1441	1162	1398	1547	1546	1546	1185	1232	1177
Net Regional Transfers -In/+Out	-1324	-1609	-1305	-1796	-1862	-1770	-1692	-1476	-1622	-1896
Inventory +Build/-Draw	51	-193	-232	-13	-11	-54	-15	12	41	
Add Product Losses, Own Use and Other	510	568	428	430	428	424	419	403	408	424
Refinery Feedstock Requirements	8448	8492	8941	8943	8968	8941	8943	8468	8494	8467
Deduct Partially Processed Oil and Other Material	-219	-391	-365	-365	-365	-365	-365	-365	-365	-365
Deduct Gas Plant Butanes supplied to Refineries	-56	-58	-73	-73	-73	-73	-73	-73	-73	-73
Refinery Requirements for Crude Oil & Equivalent	8173	8043	8503	8505	8530	8503	8505	8030	8056	8029
Per Day	22.3	22.0	23.3	23.3	23.3	23.3	23.3	22.0	22.0	22.0
Crude Oil and Equivalent Supply (thousands of cubic metres per day)										
Domestic: Heavy										
Light & Medium	22.4	22.6	23.3	23.3	23.3	23.3	23.3	22.0	22.0	22.0
Imports										
Inventory Change	-0.1	-0.6								
Total	22.3	22.0	23.3	23.3	23.3	23.3	23.3	22.0	22.0	22.0

Note: 1984 & 1985 based on Stats. Canada Catalogue 45-004.
Domestic demand plus product losses, own use and other corresponds to total products plus refinery LPG in Table A6-16 for 1986 to 2005.
[a] Domestic demand includes end-use consumption, refinery LPG sales and oil used to generate electricity and steam.

Table A6-18
Crude Oil and Equivalent Supply and Demand - Canada

(Thousands of cubic metres per day) **Low Price Case**

TOTAL CRUDE OIL	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Domestic Supply										
Actual Production & Productive Capacity										
Heavy	49.2	54.0	64.4	63.1	54.7	48.3	50.2	47.3	42.8	40.5
Light and Medium Crude Oil and Equivalent	194.3	193.6	204.3	194.1	184.0	176.0	162.5	122.6	100.3	81.0
Gas Plant Butanes	2.8	2.8	2.9	2.9	2.9	2.9	2.9	3.0	3.1	3.1
Other Material and Partially Processed Oil	4.7	6.7	6.4	6.4	6.4	6.5	6.6	4.5	4.5	4.5
Pipeline Inventory -Build/+Draft	0.3	6.1								
Total Domestic Supply of Crude Oil and Equivalent	251.3	263.2	278.0	266.5	248.0	233.7	222.2	177.4	150.7	129.1
Domestic Feedstock Requirements										
From Indigenous Sources:										
Heavy	13.5	15.2	16.2	16.8	17.0	17.3	17.5	16.5	17.7	19.0
Light and Medium Crude Oil and Equivalent	180.5	163.2	155.1	160.3	160.5	161.2	162.0	122.6	100.3	81.0
Gas Plant Butanes										
Other Material and Partially Processed Oil	7.5	9.5	9.3	9.3	9.3	9.4	9.5	7.5	7.6	7.6
From Foreign Sources	33.0	42.9	47.6	48.1	48.6	48.6	48.6	93.3	119.2	142.4
Refinery Inventory -Build/+Draft	-0.7	0.2								
Total Feedstock Requirements	233.8	231.0	228.2	234.5	235.4	236.5	237.6	239.9	244.8	250.0
Excess of Domestic Supply Over Domestic Requirements										
Heavy	36.0	41.9	48.2	46.3	37.7	31.0	32.7	30.8	25.1	21.5
Light and Medium	13.8	33.4	49.2	33.8	23.5	14.8	0.5	0.0	0.0	0.0
Total	49.8	75.3	97.4	80.1	61.2	45.8	33.2	30.8	25.1	21.5

Table A6-18 (Continued)
Crude Oil and Equivalent Supply and Demand - Canada

(Thousands of cubic metres per day)	Low Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
1. HEAVY CRUDE OIL										
Domestic Supply										
Actual Production and Productive Capacity	49.2	54.0	64.4	63.1	54.7	48.3	50.2	47.3	42.8	40.5
Inventory -Build/+Draft	0.3	3.1								
Total Supply	49.5	57.1	64.4	63.1	54.7	48.3	50.2	47.3	42.8	40.5
Domestic Feedstock Requirements From Indigenous Sources										
Atlantic	0.2	0.2								
Quebec	2.1	1.7	1.8	1.8	1.9	1.9	2.0			
Ontario	7.3	8.5	9.3	9.5	9.6	9.7	9.7	10.2	10.7	11.3
Eastern Canada	9.6	10.4	11.1	11.3	11.5	11.6	11.7	10.2	10.7	11.3
Prairies & NWT	3.9	4.8	5.1	5.5	5.5	5.7	5.8	6.3	7.0	7.7
British Columbia & Yukon										
Western Canada	3.9	4.8	5.1	5.5	5.5	5.7	5.8	6.3	7.0	7.7
Canada	13.5	15.2	16.2	16.8	17.0	17.3	17.5	16.5	17.7	19.0
Excess of Domestic Supply over Domestic Requirements	36.0	41.9	48.2	46.3	37.7	31.0	32.7	30.8	25.1	21.5
2. LIGHT AND MEDIUM CRUDE OIL AND EQUIVALENT										
Domestic Supply										
Actual Production and Productive Capacity										
East Coast										
Beaufort Sea										
W. Canada	194.3	193.6	204.3	194.1	184.0	176.0	162.5	122.6	100.3	81.0
Inventory -Build/+Draft		3.0								
Total Domestic Supply	194.3	196.6	204.3	194.1	184.0	176.0	162.5	122.6	100.3	81.0
Domestic Feedstock Requirements From Indigenous Sources										
Atlantic	8.7	2.3								
Quebec	29.1	21.7	18.8	18.8	18.7	18.7	18.6			
Ontario	71.9	68.1	69.9	72.1	71.9	72.7	73.4	51.1	25.6	2.8
Eastern Canada	109.7	92.1	88.7	90.9	90.6	91.4	92.0	51.1	25.6	2.8
Prairies & NWT	48.4	48.5	45.6	47.2	47.6	47.5	47.9	49.5	52.4	55.9
British Columbia & Yukon	22.4	22.6	20.8	22.2	22.3	22.3	22.1	22.0	22.3	22.3
Western Canada	70.8	71.1	66.4	69.4	69.9	69.8	70.0	71.5	74.7	78.2
Canada	180.5	163.2	155.1	160.3	160.5	161.2	162.0	122.6	100.3	81.0
Excess of Domestic Supply over	13.8	33.4	49.2	33.8	23.5	14.8	0.5	0.0	0.0	0.0

Table A6-18 (Continued)
Crude Oil and Equivalent Supply and Demand - Canada

(Thousands of cubic metres per day)	High Price Case									
TOTAL CRUDE OIL	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Domestic Supply										
Actual Production & Productive Capacity										
Heavy	49.2	54.0	64.9	68.2	63.7	63.2	73.1	93.7	94.3	114.2
Light and Medium Crude Oil and Equivalent	194.3	193.6	205.0	194.7	185.8	178.1	165.3	132.5	149.8	128.2
Gas Plant Butanes	2.8	2.8	2.9	2.9	2.9	2.9	2.9	3.0	3.1	3.1
Other Material and Partially Processed Oil	4.7	6.7	6.4	6.4	6.4	6.5	6.6	4.5	4.5	4.5
Pipeline Inventory -Build/+Draft	0.3	6.1								
Total Domestic Supply of Crude Oil and Equivalent	251.3	263.2	279.2	272.2	258.8	250.7	247.9	233.7	251.7	250.0
Domestic Feedstock Requirements										
From Indigenous Sources:										
Heavy	13.5	15.2	16.2	16.8	17.0	17.3	17.5	16.5	17.7	19.0
Light and Medium Crude Oil and Equivalent	180.5	163.2	152.4	158.1	158.4	158.8	158.5	132.5	149.8	128.2
Gas Plant Butanes										
Other Material and Partially Processed Oil	7.5	9.5	9.3	9.3	9.3	9.4	9.5	7.5	7.6	7.6
From Foreign Sources	33.0	42.9	46.5	47.5	48.0	48.0	48.0	73.8	59.1	83.8
Refinery Inventory -Build/+Draft	-0.7	0.2								
Total Feedstock Requirements	233.8	231.0	224.4	231.7	232.7	233.5	233.5	230.3	234.2	238.6
Excess of Domestic Supply Over Domestic Requirements										
Heavy	36.0	41.9	48.7	51.4	46.7	45.9	55.6	77.2	76.6	95.2
Light and Medium	13.8	33.4	52.6	36.6	27.4	19.3	6.8	0.0	0.0	0.0
Total	49.8	75.3	101.3	88.0	74.1	65.2	62.4	77.2	76.6	95.2

(Thousands of cubic metres per day)	High Price Case									
	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
1. HEAVY CRUDE OIL										
Domestic Supply										
Actual Production and Productive Capacity	49.2	54.0	64.9	68.2	63.7	63.2	73.1	93.7	94.3	114.2
Inventory -Build/+Draft	0.3	3.1								
Total Supply	49.5	57.1	64.9	68.2	63.7	63.2	73.1	93.7	94.3	114.2
Domestic Feedstock Requirements From Indigenous Sources										
Atlantic	0.2	0.2								
Quebec	2.1	1.7	1.8	1.8	1.9	1.9	2.0			
Ontario	7.3	8.5	9.3	9.5	9.6	9.7	9.7	10.2	10.7	11.3
Eastern Canada	9.6	10.4	11.1	11.3	11.5	11.6	11.7	10.2	10.7	11.3
Prairies & NWT	3.9	4.8	5.1	5.5	5.5	5.7	5.8	6.3	7.0	7.7
British Columbia & Yukon										
Western Canada	3.9	4.8	5.1	5.5	5.5	5.7	5.8	6.3	7.0	7.7
Canada	13.5	15.2	16.2	16.8	17.0	17.3	17.5	16.5	17.7	19.0
Excess of Domestic Supply over Domestic Requirements	36.0	41.9	48.7	51.4	46.7	45.9	55.6	77.2	76.6	95.2
2. LIGHT AND MEDIUM CRUDE OIL AND EQUIVALENT										
Domestic Supply										
Actual Production and Productive Capacity										
East Coast								3.5	17.5	17.5
Beaufort Sea									17.5	17.5
W. Canada	194.3	193.6	205.0	194.7	185.8	178.1	165.3	129.0	114.8	93.2
Inventory -Build/+Draft		3.0								
Total Domestic Supply	194.3	196.6	205.0	194.7	185.8	178.1	165.3	132.5	149.8	128.2
Domestic Feedstock Requirements From Indigenous Sources										
Atlantic	8.7	2.3						3.5	17.5	17.5
Quebec	29.1	21.7	17.9	17.9	17.8	17.8	17.7			
Ontario	71.9	68.1	67.9	70.9	71.3	72.1	72.3	61.8	62.8	38.2
Eastern Canada	109.7	92.1	85.8	88.8	89.1	89.9	90.0	65.3	80.3	55.7
Prairies & NWT	48.4	48.5	43.3	46.0	46.0	45.6	45.2	45.2	47.5	50.5
British Columbia & Yukon	22.4	22.6	23.3	23.3	23.3	23.3	23.3	22.0	22.0	22.0
Western Canada	70.8	71.1	66.6	69.3	69.3	68.9	68.5	67.2	69.5	72.5
Canada	180.5	163.2	152.4	158.1	158.4	158.8	158.5	132.5	149.8	128.2
Excess of Domestic Supply over Domestic Requirements	13.8	33.4	52.6	36.6	27.4	19.3	6.8	0.0	0.0	0.0

Appendix 7

Table A7-1
Historical Data - Natural Gas Liquids Production Canada

(Thousands of Cubic Metres per Day)

		1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Ethane	Gas Plants[a]	-	-	-	0.1	0.3	0.4	1.0	0.9	1.1	1.7
Propane	Gas Plants[a]	4.6	5.6	6.4	7.1	8.2	9.8	12.2	14.5	16.4	16.3
	Refineries[b]	1.7	1.9	2.0	2.0	2.1	2.3	2.3	2.3	2.6	2.6
	Total	6.3	7.5	8.4	9.1	10.3	12.1	14.5	16.8	19.0	18.9
Butanes	Gas Plants[a]	3.1	3.7	4.2	4.8	5.2	6.4	8.0	9.6	10.8	11.0
	Refineries[b]	1.6	1.8	1.7	1.6	1.5	1.2	0.7	0.4	0.7	0.9
	Total	4.7	5.5	5.9	6.4	6.7	7.6	8.7	10.0	11.5	11.9
Pentanes Plus	Gas Plants[a,c]	12.2	12.7	13.3	14.4	16.9	19.4	21.0	26.8	27.6	26.4

		1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Ethane	Gas Plants[a]	1.7	1.5	1.8	4.8	10.8	13.1	13.8	12.7	13.9	16.6
Propane	Gas Plants[a]	17.0	16.2	16.3	15.5	16.9	16.2	15.8	15.8	15.3	16.5
	Refineries[b]	3.1	3.5	3.7	3.6	3.5	3.8	3.7	3.2	3.5	3.6
	Total	20.1	19.7	20.0	19.1	20.4	20.0	19.5	19.0	18.8	20.1
Butanes	Gas Plants[a]	11.2	10.8	10.9	10.1	10.9	10.2	9.8	9.8	9.5	9.8
	Refineries[b]	1.0	1.0	1.4	1.5	1.9	2.3	2.9	2.5	2.6	2.4
	Total	12.2	11.8	12.3	11.6	12.8	12.5	12.7	12.3	12.1	12.2
Pentanes Plus	Gas Plants[a,c]	24.8	21.8	21.5	19.4	19.3	17.4	16.7	16.4	15.4	16.1

Notes:[a] Provincial NGL gas plant production figures have been adjusted upwards to account for each gas liquid component of mixes injected in miscible flood or other injection schemes. Production of specification ethane did not begin until 1974.

[b] Refinery production is net of own use. Source: 1965 - 1974 Statistics Canada, 1975 - 1984 NEB 145 summaries.

[c] Includes field condensate production.

Table A7-2
Natural Gas Liquids Production - Canada

(Thousands of Cubic Metres Per Day) — Low Price Case

	1985	1986	1987	1988	1989	1990	1995	2000	2005
Ethane Gas Plants	17.5	22.2	25.4	27.2	28.1	26.6	23.6	16.2	8.6
Propane Gas Plants	16.9	17.1	17.6	18.9	20.4	19.4	16.6	13.1	7.5
Refineries	3.0	2.9	3.1	3.1	3.1	3.1	3.2	3.2	3.3
Total	19.9	20.0	20.7	22.0	23.5	22.5	19.8	16.3	10.8
Butanes Gas Plants	9.7	9.8	9.9	10.5	11.3	10.8	9.1	7.2	4.3
Refineries	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.4	2.4
Total	11.9	12.0	12.2	12.8	13.6	13.1	11.4	9.6	6.7
Pentanes Plus[a] Gas Plants	17.2	17.0	17.1	17.8	18.7	17.7	14.0	11.2	6.8

High Price Case

	1985	1986	1987	1988	1989	1990	1995	2000	2005
Ethane Gas Plants	17.5	22.3	25.3	26.9	27.6	25.9	22.4	15.8	13.6
Propane Gas Plants	16.9	17.1	17.5	18.5	19.9	18.8	15.4	12.7	12.3
Refineries	3.0	2.9	3.0	3.0	3.0	3.0	3.0	3.0	3.1
Total	19.9	20.0	20.5	21.5	22.9	21.8	18.4	15.7	15.4
Butanes Gas Plants	9.7	9.8	9.9	10.3	11.0	10.4	8.4	7.0	6.9
Refineries	2.2	2.1	2.2	2.2	2.2	2.2	2.2	2.3	2.3
Total	11.9	11.9	12.1	12.5	13.2	12.6	10.6	9.3	9.2
Pentanes Plus[a] Gas Plants	17.2	17.0	17.1	17.6	18.3	17.2	13.1	10.9	10.8

Note:[a] Includes field condensate.

Table A7-3
Ethane Production from Gas Plants - Canada and Provinces

(Cubic Metres Per Day) — **Low Price Case**

	1985	1986	1987	1988	1989	1990	1995	2000	2005
Alberta									
Bonnie Glen (Texaco)	662	516	401	312	242	188	75	30	25
Elmworth (Cdn Hunter)*	347	898	1092	1091	978	859	524	207	114
Elmworth (Sulpetro)*	200	862	866	860	800	760	427	170	93
Judy Creek (Esso)*	35	2291	2795	2960	2657	2336	2838	2200	1700
Jumping Pound (Shell)	280	411	410	409	405	398	314	224	132
Kaybob South (Chevron)	0	268	1018	1139	1017	969	712	200	100
Nipisi (Amoco)*	35	31	28	25	22	20	11	7	4
Peco (Ocelot)*	0	136	270	270	270	270	270	150	85
Rainbow (Total)*	725	648	568	496	434	380	192	115	217
Swan Hills (Shell)*	30	30	27	25	24	22	16	12	10
Turner Valley(W. Decalta)	0	80	160	160	160	160	160	100	60
Waterton (Shell)	477	432	393	364	337	321	230	102	50
Wembley (Dome)	0	528	902	1002	1116	1088	1184	965	770
Other	200	200	200	200	199	198	130	110	105
Sub-Total	2791	7131	8930	9113	8462	7771	6953	4482	3360
Cochrane	5408	5559	5771	5741	5605	5076	3384	982	423
Edmonton Ethane	1172	1745	1810	1861	1900	1925	1954	1909	1836
Empress	7960	7630	8763	10307	11931	11624	11191	8710	2950
Alberta Total	17331	22065	25274	27022	27898	26396	23482	16083	8569
Saskatchewan Total	121	170	170	170	170	170	130	91	65
Canada Total	17452	22235	25444	27192	28068	26566	23612	16174	8634

Note:[*] All or part of the production is entrained in an ethane plus mix.

High Price Case

	1985	1986	1987	1988	1989	1990	1995	2000	2005
Alberta									
Field Plant Sub-Total[a]	2791	7131	8930	9113	8462	7771	6953	4482	3360
Cochrane	5408	5559	5771	5741	5605	5076	3384	982	423
Edmonton Ethane	1172	1745	1810	1861	1900	1925	1954	1909	1836
Empress	7960	7653	8607	9971	11428	10989	9994	8295	7873
Alberta Total	17331	22088	25118	26686	27395	25761	22285	15668	13492
Saskatchewan Total	121	170	170	170	170	170	130	91	65
Canada Total	17452	22258	25288	26856	27565	25931	22415	15759	13557

Note:[a] See Low Price Case for details.

Table A7-4
Propane Production from Gas Plants - Canada and Provinces

(Cubic Metres per Day)	Low Price Case								
	1985	1986	1987	1988	1989	1990	1995	2000	2005
British Columbia-Total	189	475	495	545	565	575	440	460	515
Alberta									
From Existing Plants									
Acheson (ICG)	113	102	89	77	67	58	29	14	7
Ante Creek (Amoco)*	32	28	25	22	20	18	11	7	13
Bigoray (Chevron)*	30	36	35	31	26	21	6	2	0
Bonnie Glen (Texaco)	1177	995	839	711	608	525	278	212	60
Brazeau (Chevron)*	52	65	62	58	50	43	21	13	8
Brazeau (Petro-Canada,2 Plants)*	79	105	90	81	69	63	42	18	14
Brazeau (Wolcott)*	97	92	86	80	73	66	43	25	13
Campbell Namao (Norcen)	16	15	15	13	12	12	7	3	2
Caroline (All Plants)	161	159	156	150	142	134	90	59	39
Carrot Creek (All Plants)*	50	52	51	51	50	49	47	45	30
Carson Creek (Mobil)	286	265	227	190	158	143	51	14	1
Carstairs (Home)	215	217	206	195	186	180	100	50	30
Cranberry (All Plants)*	118	116	113	110	108	106	77	46	27
Crossfield (Petrogas)	124	110	97	86	77	68	40	23	6
Elmworth (Cdn Hunter)*	131	301	394	369	334	286	172	74	41
Elmworth (Sulpetro)*	53	288	309	290	262	253	140	60	33
Ferrier (Amerada)	178	159	143	128	114	102	59	34	6
Ferrier (Others)*	44	40	36	32	28	24	15	9	6
Garrington (All Plants)*	80	63	41	36	30	21	5	0	0
Ghost Pine (Gulf)*	16	16	16	16	16	16	14	9	6
Gilby (All Plants)*	117	121	116	106	95	85	54	35	22
Harmattan Elkton (Cdn Sup)	365	450	505	494	483	477	400	192	85
Homeglen-Rimbey (Gulf)	972	835	682	574	492	429	240	236	195
Hussar (All Plants)*	81	81	81	81	81	81	81	67	47
Joffre (All Plants)*	16	15	14	11	11	10	7	4	3
Judy Creek (Esso)*	1390	1339	1236	1189	1130	1020	928	820	705
Jumping Pound (Shell)	162	163	163	162	161	158	125	88	51
Karr (Canadian Hunter)	72	142	184	184	183	182	177	138	66
Kaybob (Petro-Canada)*	113	136	121	109	98	89	50	27	16
Kaybob South (Chevron)*	428	353	289	248	202	148	29	10	7
Kaybob South (HBOG)*	379	330	260	213	165	100	0	0	0
Leduc-Woodbend (Esso)	48	45	40	37	32	28	0	0	0
Mitsue (Chevron)	97	0	0	0	210	194	131	86	56
Nevis (Gulf)	377	322	265	227	190	164	90	55	41
Nipisi (Amoco)*	56	50	45	40	36	32	21	13	6
Niton (Esso)*	27	28	28	27	27	26	25	24	20
Olds (Amerada)	50	50	50	50	50	50	40	21	13
Paddle R (Cities Service)*	122	101	85	70	58	48	15	8	4
Peco (Ocelot)*	98	101	99	96	93	89	75	36	18
Pembina (ALL PLANTS)	125	123	118	113	107	101	73	52	39
Quirk Creek (Esso)	55	117	85	149	130	110	75	43	22
Rainbow (All Plants)*	648	585	518	457	405	359	202	153	234
Redwater (Esso)	62	66	63	57	52	47	34	20	12
Ricinus (Amoco)	342	323	303	280	264	245	184	120	65
Simonette (Shell)*	32	35	30	25	22	18	12	6	4
Strachan (Gulf)	156	150	140	131	122	115	89	60	26
Swan Hills (Shell)*	61	61	58	55	51	48	35	25	16
Sylvan Lake (Chevron)	53	47	38	33	27	23	10	6	2

Note:[*] All or part of the production is entrained in an NGL mix.

(Cubic Metres per Day)	Low Price Case								
	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sylvan Lake (HBOG)	89	78	72	65	58	53	28	10	5
Sylvan Lake (General American)	26	26	25	24	23	22	21	15	7
Turner Valley (W Decalta)	91	82	73	66	58	52	30	13	11
Twinning (Mobil)	26	25	24	22	21	20	16	11	6
Waterton (Shell)	352	314	287	261	238	208	175	80	40
Wayne Rosedale (All Plants)	39	34	31	27	24	21	10	6	4
Willesden Green (Dome)	53	53	53	53	53	53	46	26	16
Willesden Green (Texaco)	23	22	21	20	19	18	14	11	9
Other Field Plants	190	167	147	138	130	123	80	60	46
Sub-Total	10445	10194	9379	8620	8031	7234	4869	3294	2261
Cochrane	1528	1571	1631	1622	1584	1434	956	277	120
Edmonton Ethane	561	821	857	981	1020	1006	910	818	726
Empress	3923	3760	4318	5079	5879	5729	5515	4290	1450
Field Plant Production From Uncommitted Reserves and Reserves Additions	0	0	670	1760	3080	3200	3730	3830	2290
Alberta-Total	16457	16346	16855	18062	19594	18603	15980	12509	6847
Saskatchewan-Total	208	260	260	260	260	255	195	135	100
Canada-Total	16854	17081	17610	18867	20419	19433	16615	13104	7462

Note:[*] All or part of the production is entrained in an NGL mix.

	High Price Case								
	1985	1986	1987	1988	1989	1990	1995	2000	2005
British Columbia-Total	189	470	490	535	560	570	405	430	450
Alberta									
Existing Field Plants[a]	10445	10194	9379	8620	8031	7234	4869	3294	2261
Cochrane	1528	1571	1631	1622	1584	1434	956	277	120
Edmonton Ethane	561	821	857	981	1020	1006	910	818	726
Empress	3923	3772	4242	4914	5632	5415	4925	4088	3880
Field Plant Production From Uncommitted Reserves and Reserves Additions	0	0	615	1615	2835	2895	3155	3635	4770
Alberta-Total	16457	16358	16724	17752	19102	17984	14815	12112	11757
Saskatchewan-Total	208	260	260	260	260	255	195	135	100
Canada-Total	16854	17088	17474	18547	19922	18809	15415	12677	12307

Note:[a] See Low Price Case for detailed plant forecasts.

Table A7-5
Butanes Production from Gas Plants - Canada and Provinces

(Cubic Metres per Day)	Low Price Case								
	1985	1986	1987	1988	1989	1990	1995	2000	2005
British Columbia-Total	208	340	350	370	390	400	315	320	345
Alberta									
From Existing Plants									
Acheson (ICG)	60	56	49	43	38	34	19	10	5
Ante Creek (Amoco)*	22	20	18	16	14	13	8	5	9
Bigoray (Chevron)*	14	18	17	15	12	10	3	1	0
Bonnie Glen (Texaco)	786	643	536	449	381	325	166	119	33
Brazeau (Chevron)*	28	35	34	32	27	23	10	5	3
Brazeau (Petro-Canada,2 Plants)*	36	47	42	38	34	34	18	10	8
Brazeau (Wolcott)*	111	102	94	86	77	71	38	23	14
Campbell Namao (Norcen)	15	14	13	11	10	9	5	2	1
Caroline (All Plants)	146	144	141	137	135	129	86	57	36
Carrot Creek (All Plants)*	32	31	30	29	28	27	24	22	14
Carson Creek (Mobil)	146	135	115	96	90	81	29	10	1
Carstairs (Home)	165	153	142	132	124	116	58	27	16
Cranberry (All Plants)*	75	74	72	70	69	68	50	29	18
Crossfield (Petrogas)	92	80	71	63	56	50	30	17	5
Elmworth (Cdn Hunter)*	55	126	167	156	140	120	73	31	17
Elmworth (Sulpetro)*	22	122	130	122	110	107	59	25	14
Ferrier (Amerada)	99	85	74	65	58	53	30	18	5
Ferrier (Others)*	38	34	30	27	25	23	13	8	5
Garrington (All Plants)*	44	36	26	21	15	11	3	0	0
Ghost Pine (Gulf)*	25	25	25	25	25	25	22	14	9
Gilby (All Plants)*	83	85	81	73	66	59	37	24	16
Harmattan Elkton (Cdn Sup)	267	369	359	349	339	343	290	140	62
Homeglen-Rimbey (Gulf)	524	455	363	298	249	211	109	105	90
Hussar (All Plants)	65	65	65	65	65	65	65	53	37
Joffre (All Plants)*	14	13	10	10	9	7	5	3	2
Judy Creek (Esso)*	730	831	784	747	678	620	492	360	324
Jumping Pound (Shell)	140	141	141	141	140	138	111	79	46
Karr (Canadian Hunter)	29	58	75	75	74	74	72	55	27
Kaybob (Petro-Canada)*	95	114	101	91	82	74	41	23	15
Kaybob South (Chevron)*	448	377	312	268	221	165	38	15	10
Kaybob South (HBOG)*	411	345	280	228	185	135	0	0	0
Leduc-Woodbend (Esso)	38	35	32	29	26	23	0	0	0
Mitsue (Chevron)	62	0	0	0	135	125	84	55	36
Nevis (Gulf)	220	195	166	142	123	108	64	43	33
Nipisi (Amoco)*	45	41	36	32	29	26	15	9	4
Niton (Esso)	27	30	29	29	29	28	28	27	20
Olds (Amerada)	35	35	35	35	35	35	28	16	10
Paddle R (Cities Service)*	67	56	47	39	33	27	9	5	2
Peco (Ocelot)*	49	51	50	49	48	46	39	19	9
Pembina (All Plants)	81	80	77	73	70	66	47	33	25
Quirk Creek (Esso)	42	96	70	122	100	92	50	28	16
Rainbow (All Plants)*	513	454	403	356	315	279	157	118	181
Redwater (Esso)	51	43	41	37	36	34	30	19	12
Ricinus (Amoco)	195	186	173	160	148	142	117	90	50
Simonette (Shell)*	22	22	19	16	13	10	6	3	2
Strachan (Gulf)	128	120	115	107	101	93	68	46	14
Swan Hills (Shell)*	31	31	29	28	26	24	17	13	8
Sylvan Lake (Chevron)	35	30	26	22	19	15	7	3	1

Note:[*] All or part of the production is entrained in an NGL mix.

Table A7-5 (Continued)
Butanes Production from Gas Plants - Canada and Provinces

(Cubic Metres per Day)

Low Price Case

	1985	1986	1987	1988	1989	1990	1995	2000	2005
Sylvan Lake (HBOG)	48	47	39	37	32	28	18	6	3
Sylvan Lake (General American)	24	24	24	23	23	23	23	18	9
Tumer Valley (W Decalta)	63	54	47	42	37	33	20	7	6
Twinning (Mobil)	10	10	9	8	8	8	6	4	3
Waterton (Shell)	291	258	235	214	193	172	152	70	34
Wayne Rosedale (All Plants)	38	33	30	26	24	21	11	6	4
Willesden Green (Dome)	45	45	45	45	45	45	44	26	13
Willesden Green (Texaco)	13	12	12	11	11	10	8	6	5
Other Field Plants	105	90	80	73	69	65	44	31	23
Sub-Total	7095	6911	6266	5733	5304	4798	3096	1991	1365
Cochrane	505	519	539	536	523	474	316	92	40
Edmonton Ethane	204	342	346	400	437	443	437	390	332
Empress	1583	1518	1743	2050	2374	2313	2226	1732	584
Field Plant Production From Uncommitted Reserves and Reserves Additions	0	0	500	1200	2100	2170	2535	2600	1560
Alberta-Total	9387	9290	9394	9919	10738	10198	8610	6805	3881
Saskatchewan-Total	131	165	165	165	165	162	125	85	60
Canada-Total	9726	9795	9909	10454	11293	10760	9050	7210	4286

Note:[*] All or part of the production is entrained in an NGL mix.

High Price Case

	1985	1986	1987	1988	1989	1990	1995	2000	2005
British Columbia-Total	208	335	345	370	385	390	300	305	315
Alberta									
Existing Field Plants[a]	7095	6911	6266	5733	5304	4798	3096	1991	1365
Cochrane	505	519	539	536	523	474	316	92	40
Edmonton Ethane	204	342	346	400	437	443	437	390	332
Empress	1583	1523	1712	1984	2273	2186	1988	1650	1566
Field Plant Production From Uncommitted Reserves and Reserves Additions	0	0	480	1095	1925	1965	2145	2470	3240
Alberta-Total	9387	9295	9343	9748	10462	9866	7982	6593	6543
Saskatchewan-Total	131	165	165	165	165	162	125	85	60
Canada-Total	9726	9795	9853	10283	11012	10418	8407	6983	6918

Note:[a] See Low Price Case for detailed plant forecasts.

Table A7-6
Pentanes Plus Production from Gas Plants - Canada and Provinces

(Cubic Metres per Day)	Low Price Case								
	1985	1986	1987	1988	1989	1990	1995	2000	2005
From Existing Plants									
British Columbia[a]									
Total	375	388	396	411	430	450	365	367	379
Alberta									
Bow River Pipelines									
Empress (Petro-Canada)	280	250	305	305	305	305	305	305	79
Provost	42	39	36	33	31	29	20	14	10
Vulcan	25	22	19	17	15	13	7	4	2
Others	43	41	38	35	32	26	21	16	13
Total	390	352	398	390	383	373	353	339	104
Co-ed Pipe Line									
Caroline (Dome)	163	160	156	142	122	101	58	38	25
Cochrane	201	206	214	213	208	189	126	36	16
Edmonton Ethane	79	205	208	235	260	264	248	187	108
Empress (Dome)	348	326	353	477	609	584	549	399	159
Empress (Wolcott)	12	40	50	50	50	50	50	0	0
Ferrier (4 Plants)	50	45	40	36	33	29	18	12	7
Garrington (4 Plants)	34	30	26	23	20	15	8	0	0
Judy Creek (Esso)*	540	537	508	460	450	427	350	280	233
Leduc-Woodbend	47	39	32	26	22	18	0	0	0
Minnehik-Rosedale (Candel)	108	98	90	84	78	70	42	26	16
Pembina	193	193	191	182	177	169	132	105	81
Quirk Creek	60	131	95	166	150	140	98	54	28
Ricinus (Amoco)	275	250	230	210	201	185	115	80	25
Ricinus West (Canterra)	110	112	115	122	126	125	119	51	21
Strachan (Gulf)	457	424	402	352	327	302	215	146	35
Willesden Green (Dome)	33	33	33	33	33	33	29	18	11
Others	28	23	17	16	15	14	10	7	5
Total	2738	2852	2760	2827	2881	2715	2167	1439	770
Cremona Pipeline									
Bumt Timber (Shell)	31	31	31	31	31	30	19	12	8
Carstairs (Home)	294	275	250	217	200	190	95	45	25
Crossfield (Petrogas)	164	148	130	115	102	90	43	24	2
Crossfield East (Amoco)	17	17	17	17	17	17	11	7	5
Harmattan Elkton (Cdn Superio	511	575	625	653	641	640	530	247	109
Lone Pine Creek (Cdn Sup)	17	16	15	13	12	11	6	4	2
Lone Pine Creek (HBOG)	111	143	179	174	159	144	89	55	34
Olds (Amerada)	68	69	67	65	64	62	49	30	18
Others	22	22	21	20	20	19	15	8	5
Total	1235	1296	1335	1305	1246	1203	857	432	208

Note:[*] All or part of the production is entrained in an NGL mix.

Table A7-6 (Continued)
Pentanes Plus Production from Gas Plants - Canada and Provinces

(Cubic Metres per Day)	Low Price Case								
	1985	1986	1987	1988	1989	1990	1995	2000	2005
Federated Pipe Lines									
Total	224	211	197	181	166	154	107	74	51
Gibson Petroleum									
Acheson (ICG)	37	38	33	28	24	21	10	5	2
Paddle River	40	36	34	30	26	22	8	4	2
Wilson Creek (Amerada)	26	26	24	22	20	18	12	6	3
Total	103	100	91	80	70	61	30	15	7
Gulf Alberta Pipe Line									
Cessford (HBOG)	13	14	14	14	14	14	14	12	9
Ghost Pine (Gulf)*	42	42	43	44	44	44	37	23	14
Hussar (Canterra)	37	37	37	37	37	37	37	25	17
Nevis (Chevron)	14	13	12	11	10	9	6	4	2
Nevis (Gulf)	164	155	139	126	115	106	78	58	40
Wayne Rosedale (All Plants)	55	50	47	43	39	37	24	15	11
Others	175	163	151	140	131	122	84	59	41
Total	500	474	443	415	390	369	280	196	134
Imperial Pipeline Excelsior									
Others	2	2	2	2	1	1	1	1	1
Total	2	2	2	2	1	1	1	1	1
Imperial Pipe Line - Ellerslie									
Campbell Namao (Norcen)	15	13	12	11	9	5	2	0	0
Total	15	13	12	11	9	5	2	0	0
Imperial Pipe Line - Redwater									
Redwater	27	25	23	21	20	19	15	9	6
Total	27	25	23	21	20	19	15	9	6
Murphy Oil									
Total	2	2	2	2	2	2	1	1	1

Note:[*] All or part of the production is entrained in an NGL mix.

Table A7-6 (Continued)
Pentanes Plus Production from Gas Plants - Canada and Provinces

(Cubic Metres per Day)	1985	1986	1987	1988	1989	1990	1995	2000	2005
			Low Price Case						
			Peace River Oil Pipe Line						
Carson Creek (Mobil)	170	164	155	145	126	124	51	17	7
Dunvegan (Anderson)	144	130	115	100	91	83	60	35	23
Elmworth (Total)	132	254	304	283	257	233	136	57	32
Gold Creek	95	91	86	82	80	79	55	26	0
Greencourt	8	8	8	8	8	8	6	3	2
Josephine	33	47	49	49	49	49	38	18	10
Karr(Cdn Hunter)*	35	64	81	80	79	77	72	55	27
Kaybob (Petro-Canada)	106	135	129	122	118	115	8	45	26
Kaybob South (Chevron)*	1545	1379	1200	1128	846	637	173	68	44
Kaybob South (HBOG)*	946	920	880	870	700	560	0	0	0
Simonette (Shell)	55	50	45	38	27	22	15	8	4
Sinclair (Dome)	54	45	33	25	19	6	3	0	0
Sturgeon Lake South	69	68	61	55	49	45	27	16	10
Wapiti	90	86	80	74	69	64	45	31	22
Whitecourt	21	21	21	21	21	21	20	12	8
Windfall	276	230	169	125	97	73	29	15	10
Others	91	85	78	75	70	64	43	31	26
Total	3870	3777	3494	3280	2706	2260	781	437	251
			Pembina Pipe Line						
Brazeau (Canterra)	41	44	43	39	36	33	22	16	10
Brazeau (HBOG)	133	152	169	166	164	161	98	60	37
Brazeau (Petro-Canada,2 Plar	217	401	380	356	342	327	256	195	143
Brazeau (Wolcott)	1220	1146	1077	980	895	814	508	317	170
Carrot Creek (Amoco & Sabine	24	25	25	25	25	25	24	23	17
Leaman (Dome)*	14	14	13	12	11	10	7	4	2
Niton (Esso)	38	36	36	35	35	35	34	34	25
Peco (Ocelot)*	77	76	73	71	69	65	56	27	13
Pembina	392	392	388	370	360	343	267	212	163
Rosevear (Shell)	29	29	29	29	29	29	22	14	8
Rosevear (Suncor)	20	20	20	20	20	20	13	9	6
Willesden Green (2 Plants)	19	18	17	16	16	15	15	9	7
Others	53	53	46	44	40	34	21	13	6
Total	2277	2406	2316	2163	2042	1911	1343	933	607
			Rainbow Pipe Line						
Cranberry (Dome)	400	493	483	471	462	455	366	201	120
Cranberry (Shell)	33	40	40	40	37	34	22	13	8.
Mitsue (Chevron)	32	0	0	0	77	71	48	32	21
Nipisi (Amoco)*	25	22	20	18	16	14	8	4	2
Rainbow (Total)*	541	508	465	428	396	368	224	170	306
Total	1031	1063	1008	957	988	942	668	420	457

Note:[*] All or part of the production is entrained in an NGL mix.

Table A7-6 (Continued)
Pentanes Plus Production from Gas Plants - Canada and Provinces

(Cubic Metres per Day)	1985	1986	1987	1988	1989	1990	1995	2000	2005
	Low Price Case								
Rangeland Pipe Line									
Caroline (Citadel & HBOG)	117	132	130	129	128	126	84	56	38
Ferrier (Amerada)	75	70	60	54	48	43	25	15	3
Gilby (Chevron)*	24	24	23	21	19	17	10	6	3
Gilby (Petro-Canada)*	53	63	63	63	57	51	34	24	17
Gilby (Others)	22	20	19	18	16	14	10	6	5
Innisfail (Shell)	29	23	18	14	11	9	3	0	0
Sylvan Lake (Chevron)	25	22	19	17	15	13	7	4	2
Sylvan Lake (Gen American)	40	40	39	39	38	38	35	25	12
Sylvan Lake (HBOG)	46	43	40	35	30	26	16	8	3
Twinning (Mobil)	17	17	15	14	13	12	10	7	5
Waterton (Shell)	999	850	735	646	577	519	360	150	80
Wimborne (Mobil)	30	28	26	23	20	18	10	6	4
Others	38	35	33	31	29	27	18	13	9
Total	1515	1367	1220	1104	1001	913	622	320	181
Rimbey Pipe Line									
Bonnie Glen (Texaco)	748	671	576	500	436	385	228	188	53
Homeglen-Rimbey (Gulf)	684	560	430	340	300	251	125	105	90
Total	1432	1231	1006	840	736	636	353	293	143
Texaco Canada Resources									
Others	2	2	2	2	1	1	1	1	1
Total	2	2	2	2	1	1	1	1	1
Valley Pipe Line									
Gilby (Texaco)	47	45	42	38	33	30	17	10	6
Jumping Pound (Shell)	401	385	370	365	355	340	268	192	110
Turner Valley (West Decalta)	50	44	38	34	30	27	15	4	3
Wildcat Hills (Petro-Canada)	64	64	64	64	64	63	38	23	14
Total	515	493	472	463	449	430	321	219	127
Truck and Tank Car									
Edson (HBOG)	180	151	149	140	130	119	70	41	24
Sundance (Dome)	34	25	19	14	10	8	2	0	0
Others	250	225	204	196	178	165	96	67	46
Total	464	401	372	350	318	292	168	108	70

Note:[*] All or part of the production is entrained in an NGL mix.

Table A7-6 (Continued)
Pentanes Plus Production from Gas Plants - Canada and Provinces

(Cubic Metres per Day)	Low Price Case								
	1985	1986	1987	1988	1989	1990	1995	2000	2005
				Field Condensate					
Total	416	402	440	485	530	525	450	370	163
Sub-Total	16758	16469	15593	14878	13939	12812	8520	5607	3282
Field Plant Production From Uncommitted Reserves and Reserves Additions	0	0	1010	2400	4180	4340	5070	5200	3120
Alberta-Total	16758	16469	16603	17278	18119	17152	13590	10807	6402
				Saskatchewan[a]					
Total	97	115	115	115	115	112	85	60	45
				Canada					
Canada-Total	17230	16972	17114	17804	18664	17714	14040	11234	6826

Note:[*] All or part of the production is entrained in an NGL mix.
[a] Includes field condensate.

	High Price Case								
	1985	1986	1987	1988	1989	1990	1995	2000	2005
British Columbia-Total	375	388	395	410	420	435	350	355	360
Alberta									
Bow River Pipelines	390	352	398	390	383	373	353	339	355
Co-ed Pipe Line	2738	2854	2747	2800	2840	2663	2070	1405	957
Cremona Pipeline	1235	1296	1335	1305	1246	1203	857	432	208
Federated Pipe Lines	224	211	197	181	166	154	107	74	51
Gibson Petroleum	103	100	91	80	70	61	30	15	7
Gulf Alberta Pipe Line	500	474	443	415	390	369	280	196	134
Imperial Pipeline Excelsior	2	2	2	2	1	1	1	1	1
Imperial Pipeline Ellerslie	15	13	12	11	9	5	2	0	0
Imperial Pipeline Redwater	27	25	23	21	20	19	15	9	6
Murphy Oil	2	2	2	2	2	2	1	1	1
Peace River Oil Pipe Line	3870	3777	3494	3280	2706	2260	781	437	251
Pembina Pipe Line	2277	2406	2316	2163	2042	1911	1343	933	607
Rainbow Pipe Line	1031	1063	1008	957	988	942	668	420	457

Table A7-6 (Continued)
Pentanes Plus Production from Gas Plants - Canada and Provinces

(Cubic Metres per Day)	High Price Case								
	1985	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Rangeland Pipe Line	1515	1367	1220	1104	1001	913	622	320	181
Rimbey Pipe Line	1432	1231	1006	840	736	636	353	293	143
Texaco Canada Resources	2	2	2	2	1	1	1	1	1
Valley Pipe Line	515	493	472	463	449	430	321	219	127
Truck and Tank Car	464	401	372	350	318	292	168	108	70
Field Condensate	416	403	437	478	520	509	421	364	364
Alberta Sub-Total	16758	16472	15577	14844	13888	12744	8394	5567	3921
Field Plant Prioduction from Uncommited Reserves and Reserves Additions	0	0	970	2190	3850	3930	4290	4940	6500
Alberta-Total	16758	16472	16547	17034	17738	16674	12684	10507	10421
Saskatchewan-Total[a]	97	115	115	115	115	112	85	60	45
Canada-Total	17230	16975	17057	17559	18273	17221	13119	10922	10826

Note:[a] Includes field condensate.

Table A7-7
Propane Production from Refineries - Canada and Regions

(Cubic Metres Per Day)				Low Price Case					
	1985	**1986**	**1987**	**1988**	**1989**	**1990**	**1995**	**2000**	**2005**
Atlantic	215	230	234	240	239	239	239	239	257
Quebec	726	695	695	695	695	695	730	730	730
Ontario	795	789	822	834	841	849	849	851	848
Prairies	913	871	914	915	914	922	960	1024	1093
British Columbia	383	359	385	389	387	383	383	389	387
Canada Total	3032	2944	3050	3073	3076	3088	3161	3233	3315

				High Price Case					
	1985	1986	1987	1988	1989	1990	1995	2000	2005
Atlantic	215	220	229	234	235	234	218	227	233
Quebec	726	680	680	682	680	680	680	682	680
Ontario	795	789	821	828	836	838	830	833	830
Prairies	913	818	869	870	864	861	869	919	977
British Columbia	383	403	403	404	403	403	382	383	382
Canada Total	3032	2910	3002	3018	3018	3016	2979	3044	3102

Note: Supply is net of energy supply industry own use.

Table A7-8
Butanes Production from Refineries - Canada and Regions

(Cubic Metres Per Day)

Low Price Case

	1985	1986	1987	1988	1989	1990	1995	2000	2005
Atlantic	90	97	99	101	101	101	101	101	108
Quebec	576	551	551	551	551	551	579	579	579
Ontario	718	712	742	754	760	767	767	768	766
Prairies	670	638	670	670	669	677	702	750	801
British Columbia	194	181	194	196	195	193	193	196	195
Canada Total	2248	2179	2256	2272	2276	2289	2342	2394	2449

High Price Case

	1985	1986	1987	1988	1989	1990	1995	2000	2005
Atlantic	90	92	96	99	99	98	92	95	98
Quebec	576	539	539	540	539	539	539	540	539
Ontario	718	714	742	749	756	757	751	753	751
Prairies	670	600	638	639	634	632	638	674	717
British Columbia	194	204	204	204	204	204	193	194	193
Canada Total	2248	2149	2219	2231	2232	2230	2213	2256	2298

Note: Supply is net of energy supply industry own use.

Table A7-9
End Use Demand for Ethane, Propane and Butanes by Sector - Canada

(Petajoules)

Low Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Ethane										
Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Petrochemical	54.4	72.0	76.0	80.0	80.4	80.8	81.2	99.6	126.3	126.3
Other Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total End Use	54.4	72.0	76.0	80.0	80.4	80.8	81.2	99.6	126.3	126.3
Propane										
Residential	34.4	34.2	34.6	35.0	35.4	35.6	35.8	37.2	39.3	41.3
Commercial	16.4	16.3	16.8	17.4	17.9	18.2	18.5	20.9	24.0	27.2
Petrochemical	13.5	16.3	18.3	22.0	25.7	28.5	34.4	36.0	36.0	36.0
Other Industrial	10.8	10.9	11.3	11.6	11.9	12.2	12.4	14.1	15.9	18.7
Transportation	12.4	14.0	14.6	15.2	15.8	16.4	17.0	18.0	19.0	20.0
Total End Use	87.4	91.8	95.6	101.1	106.7	111.0	118.0	126.2	134.2	143.1
Butanes										
Residential	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Petrochemical	9.6	11.5	13.5	19.3	23.4	26.1	24.9	26.0	26.0	26.0
Other Industrial	1.6	1.5	1.5	1.5	1.6	1.6	1.6	1.9	2.1	2.4
Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total End Use	11.2	13.1	15.1	20.9	25.1	27.8	26.6	28.0	28.2	28.5

High Price Case

	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
Ethane										
Residential	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Petrochemical	54.4	72.0	76.0	80.0	80.4	80.8	81.2	99.6	126.3	126.3
Other Industrial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total End Use	54.4	72.0	76.0	80.0	80.4	80.8	81.2	99.6	126.3	126.3
Propane										
Residential	34.4	34.2	34.4	34.7	34.7	34.7	34.5	35.0	36.8	38.8
Commercial	16.4	16.3	16.8	17.2	17.5	17.7	17.9	19.7	22.4	25.0
Petrochemical	13.5	16.3	18.3	22.0	25.7	28.5	34.4	36.0	36.0	36.0
Other Industrial	10.8	10.9	11.4	11.6	11.9	12.2	12.3	13.9	15.5	17.9
Transportation	12.4	14.0	15.2	16.4	17.6	18.8	20.0	23.5	27.1	30.5
Total End Use	87.4	91.8	96.1	101.9	107.4	111.8	119.1	128.1	137.8	148.2
Butanes										
Residential	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Petrochemical	9.6	11.5	13.5	19.3	23.4	26.1	24.9	26.0	26.0	26.0
Other Industrial	1.6	1.5	1.5	1.6	1.6	1.6	1.7	1.9	2.1	2.4
Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total End Use	11.2	13.1	15.1	21.0	25.1	27.8	26.7	28.0	28.2	28.5

(Thousands of Cubic Meters Per Day)

Low Price Case

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Supply											
Total	17.5	22.2	25.4	27.2	28.1	26.6	25.5	24.7	24.2	23.9	23.6
Demand											
Miscible Fluid Requirements	3.4	9.8	11.8	12.8	11.4	9.8	5.7	5.4	5.3	3.5	2.0
Other Canadian Requirements [a]	10.7	11.3	11.9	12.0	12.1	12.1	12.2	12.3	12.4	12.5	14.9
Total	14.1	21.1	23.7	24.8	23.5	21.9	17.9	17.7	17.7	16.0	16.9
Potential Exports	3.4	1.1	1.7	2.4	4.6	4.7	7.6	7.0	6.5	7.9	6.7

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Supply										
Total	21.9	20.1	18.9	18.2	16.2	14.2	12.4	11.0	9.7	8.6
Demand										
Miscible Fluid Requirements	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Canadian Requirements [a]	17.8	18.5	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8
Total	18.4	18.5	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8
Potential Exports	3.5	1.6	0.1	-0.6	-2.6	-4.6	-6.4	-7.8	-9.1	-10.2

High Price Case

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Supply											
Total	17.5	22.3	25.3	26.9	27.6	25.9	24.7	23.8	23.2	23.1	22.4
Demand											
Miscible Fluid Requirements	3.4	9.8	11.8	14.0	15.5	13.8	12.5	11.5	10.8	10.6	7.5
Other Canadian Requirements [a]	10.7	11.3	11.9	12.0	12.1	12.1	12.2	12.3	12.4	12.5	14.9
Total	14.1	21.1	23.7	26.0	27.6	25.9	24.7	23.8	23.2	23.1	22.4
Potential Exports	3.4	1.2	1.6	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Supply										
Total	20.5	18.6	17.3	16.5	15.8	15.6	15.5	15.2	14.5	13.6
Demand										
Miscible Fluid Requirements	6.3	5.1	3.9	2.7	1.5	0.0	0.0	0.0	0.0	0.0
Other Canadian Requirements [a]	17.8	18.5	18.8	18.8	18.8	18.8	18.8	18.8	18.8	18.8
Total	24.1	23.6	22.7	21.5	20.3	18.8	18.8	18.8	18.8	18.8
Potential Exports	-3.6	-5.0	-5.4	-5.0	-4.5	-3.2	-3.3	-3.6	-4.3	-5.2

Nota: [a] Miscible fluid requirements are net requirements after accounting for reproduced fluids from hydrocarbon miscible projects.

Table A7-11
Propane Supply and Demand - Canada

(Thousands of Cubic Metres per Day) — **Low Price Case**

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Supply											
Total	19.9	20.0	20.7	22.0	23.5	22.5	21.7	20.9	20.4	20.3	19.8
Demand											
Miscible Fluid Requirements[a]	2.6	2.7	2.9	3.2	2.8	2.4	2.0	1.6	1.2	0.8	0.4
Other Canadian Requirements	9.9	10.3	10.9	11.5	11.9	12.7	12.9	13.1	13.2	13.4	13.5
Total	12.5	13.0	13.8	14.7	14.7	15.1	14.9	14.7	14.4	14.2	13.9
Potential Exports	7.4	7.0	6.9	7.3	8.8	7.4	6.8	6.2	6.0	6.1	5.9

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Supply										
Total	19.0	18.1	17.6	17.4	16.3	14.9	13.6	12.6	11.6	10.8
Demand										
Miscible Fluid Requirements[a]	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Canadian Requirements	13.7	13.9	14.0	14.2	14.4	14.6	14.8	15.0	15.2	15.4
Total	13.8	13.9	14.0	14.2	14.4	14.6	14.8	15.0	15.2	15.4
Potential Exports	5.2	4.2	3.6	3.2	1.9	0.3	-1.2	-2.4	-3.6	-4.6

High Price Case

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Supply											
Total	19.9	20.0	20.5	21.5	22.9	21.8	20.8	19.9	19.3	19.1	18.4
Demand											
Miscible Fluid Requirements[a]	2.6	2.7	2.9	3.5	4.0	4.3	3.4	3.1	3.0	2.4	2.0
Other Canadian Requirements	9.9	10.3	10.9	11.5	12.0	12.8	13.0	13.2	13.4	13.5	13.7
Total	12.5	13.0	13.8	15.0	16.0	17.1	16.4	16.3	16.4	15.9	15.7
Potential Exports	7.4	7.0	6.7	6.5	6.9	4.7	4.4	3.6	2.9	3.2	2.7

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Supply										
Total	17.5	16.5	16.0	15.8	15.7	15.9	16.2	16.2	15.9	15.4
Demand										
Miscible Fluid Requirements[a]	1.7	1.4	1.0	0.7	0.4	0.0	0.0	0.0	0.0	0.0
Other Canadian Requirements	13.9	14.1	14.3	14.6	14.8	15.0	15.2	15.4	15.7	15.9
Total	15.6	15.5	15.3	15.3	15.2	15.0	15.2	15.4	15.7	15.9
Potential Exports	1.9	1.0	0.7	0.5	0.5	0.9	1.0	0.8	0.2	-0.5

Note:[a] Miscible fluid requirements are net requirements after accounting for reproduced fluids from hydrocarbon miscible projects.

Table A7-12
Butanes Supply and Demand - Canada

(Thousands of Cubic Metres per Day)

Low Price Case

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Supply											
Total	11.9	12.0	12.2	12.8	13.6	13.1	12.5	12.1	11.8	11.7	11.4
Demand											
Miscible Fluid Requirements[a]	0.9	1.0	1.1	1.2	1.0	0.9	0.7	0.6	0.4	0.3	0.2
Other Canadian Requirements	4.2	4.3	4.9	5.3	5.6	5.5	5.5	5.7	5.7	5.7	5.8
Total	5.1	5.3	6.0	6.5	6.6	6.4	6.2	6.3	6.1	6.0	6.0
Potential Exports	6.8	6.7	6.2	6.3	7.0	6.7	6.3	5.8	5.7	5.7	5.4

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Supply										
Total	10.9	10.6	10.3	10.2	9.5	8.6	7.6	7.0	6.2	5.4
Demand										
Miscible Fluid Requirements[a]	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Canadian Requirements	5.8	5.8	5.9	5.9	5.9	6.0	6.0	6.0	6.1	6.1
Total	5.9	5.8	5.9	5.9	5.9	6.0	6.0	6.0	6.1	6.1
Potential Exports	5.0	4.8	4.4	4.3	3.6	2.6	1.6	1.0	0.1	-0.7

High Price Case

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Supply											
Total	11.9	11.9	12.1	12.5	13.2	12.6	12.0	11.5	11.1	11.0	10.6
Demand											
Miscible Fluid Requirements[a]	0.9	1.0	1.1	1.3	1.4	1.5	1.2	1.1	1.1	0.9	0.7
Other Canadian Requirements	4.2	4.3	4.9	5.2	5.5	5.4	5.4	5.5	5.5	5.5	5.5
Total	5.1	5.3	6.0	6.5	6.9	6.9	6.6	6.6	6.6	6.4	6.2
Potential Exports	6.8	6.6	6.1	6.0	6.3	5.7	5.4	4.9	4.5	4.6	4.4

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Supply										
Total	10.1	9.6	9.4	9.3	9.3	9.4	9.6	9.6	9.5	9.2
Demand										
Miscible Fluid Requirements[a]	0.6	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0
Other Canadian Requirements	5.5	5.5	5.5	5.5	5.6	5.6	5.6	5.6	5.6	5.6
Total	6.1	6.0	5.9	5.8	5.7	5.6	5.6	5.6	5.6	5.6
Potential Exports	4.0	3.6	3.5	3.5	3.6	3.8	4.0	4.0	3.9	3.6

Note:[a] Miscible fluid requirements are net requirements after accounting for reproduced fluids from hydrocarbon miscible projects.

Appendix 8

Table A8-1
Historical Data - Coal Production, Imports and Exports - Canada

(Megatonnes)	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Production										
Bituminous	6.3	6.1	6.1	5.4	5.0	8.0	9.7	11.4	12.3	12.5
Subbituminous	2.3	2.3	2.4	2.7	2.9	3.6	4.0	4.5	4.5	5.1
Lignite	1.9	1.9	1.8	2.0	1.8	3.5	3.0	3.0	3.7	3.5
Total	10.5	10.3	10.3	10.2	9.7	15.1	16.7	18.8	20.5	21.1
Imports	14.8	14.8	14.4	15.7	15.6	17.6	16.2	16.8	15.1	12.4
Exports	1.1	1.1	1.2	1.3	1.3	4.0	7.0	8.6	10.3	10.5

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Production										
Bituminous	15.8	14.4	15.3	17.1	18.4	20.2	21.7	22.3	22.6	32.1
Subbituminous	6.0	6.4	7.9	8.3	9.6	10.5	11.6	13.0	14.5	15.4
Lignite	3.5	4.7	5.5	5.1	5.0	6.0	6.8	7.5	7.8	9.9
Total	25.3	25.5	28.7	30.5	33.0	36.7	40.1	42.8	44.8	57.4
Imports	15.8	14.6	15.4	14.1	17.5	15.9	14.8	15.8	14.7	18.4
Exports	11.4	11.9	12.4	14.0	13.7	15.3	15.7	16.0	17.0	25.1

Source: Energy Statistics Handbook, Energy, Mines and Resources.

Table A8-2
Estimates of Coal Resources in Canada

(Megatonnes)		Resources of Immediate Interest			Resources of Future Interest		
Area	**Coal Rank[a]**	**Measured**	**Indicated**	**Inferred**	**Measured**	**Indicated**	**Inferred**
		(1)	(2)	(3)	(4)	(5)	(6)
Nova Scotia[c]							
Sydney	hvb	156 [b]	1428 [q]	719	-	-	-
Other	hvb	48	41	38	3	50	128
Subtotal		204	1469	757	3	50	128
New Brunswick[d]							
Minto	hvb	6	13	-	-	-	-
Other	hvb	14	14	1	-	-	-
Subtotal		20	27	1	-	-	-
Ontario[e]	lig	218	-	-	-	-	-
Saskatchewan[f]							
Estevan	lig	283	497	437	41	519	6998
Willow Bunch	lig	747	1044	1420	68	1704	10388
Wood Mountain	lig	278	733	1114	44	1447	5665
Cypress	lig	162	407	465	8	243	461
Subtotal		1470	2681	3436	161	3913	23512
Alberta[g]							
Plains	sub (& some hvb & lig)	41860 [h]	- [i]	- [j]	-	-	1750000 [m]
Foothills	hvb	2490	-	5010 [k]	-	-	7500 [n]
Mountains	lvb - mvb (& some hvb)	7760	-	6740 [l]	-	-	14500 [o]
Subtotal		52110	-	11750	-	-	1772000
British Columbia[p]							
Southeastern	lvb - mvb	6286	9436	36317	-	-	-
Northeastern	lvb - mvb	996	462	7719	-	-	-
Other	mainly lig (& some sub - hvb)	1845	91	7439	-	-	-
Subtotal		9127	9989	51475	-	-	-
Canada - Totals	lig	3533	2772	10875	161	3913	23512
	sub	41860	-	-	-	-	1750000
	hvb	2714	1496	5768	3	50	7628
	lvb - mvb	15042	9898	50776	-	-	14500
	total	63149	14166	67419	164	3963	1795640

[a] lig = lignitic; sub = subbituminous; hvb = high volatile bituminous; mvb = medium volatile bituminous; lvb = low volatile bituminous.
[b] Resources from ER79-9 less production between 1978 and 1982.
[c] Based on federal/provincial drilling program and data from Cape Breton Development Corp.
[d] Based on information provided by New Brunswick Department of Natural Resources and N. B. Coal Ltd.
[e] Based on EMR study.
[f] Based on federal/provincial coal resource evaluation program in 1978, less production up to 1984.
[g] Estimates for Alberta are based on Energy Resources Conservation Board Report 84-31. Work by Williams and Murphy, 1981, indicates that ERCB estimates up to December 1980 and earlier have been excessively conservative in identifying total coal resources for the Plains Region. Accordingly, ERCB has accepted the tenfold increase in the resource tonnage for plains coal as more realistic than earlier estimates. It should be noted that ERCB's parameters, evaluation methodology and reporting terminology differ from those used by EMR.
For this table, the following accomodations have been made:
[h] ERCB "established resources" are reported as EMR "measured resources"; it is recognized these figures include some tonnages that EMR would report as "indicated".
[i] There is no ERCB category comparable to EMR "indicated".
[j] There is no ERCB category comparable to EMR "inferred resources of immediate interest".
[k] Represents one-half of ERCB "total resources" (15.0 gigatonnes) less all of ERCB "established resources" (2.26 gigatonnes).
[l] Represents one-half of ERCB "total resources" (29 gigatonnes) less all of ERCB " established resources" (7.76 gigatonnes).
[m] Refers to resources identified by Williams and Murphy, 1981, for all five Rieliability Index categories for seams 2 metres thick from base of surface casing (+-150 m) to 500 metres deep.
[n] Represents one-half of ERCB "total resources" (15 gigatonnes).
[o] Represents one-half of ERCB "total resources" (29 gigatonnes).
[p] Based on evaluations by EMR, British Columbia Ministry of Energy, Mines and Petroleum Resources and British Columbia Hydro.
[q] "Demonstrated" resources of Hacquebard (1983) less "measured resources"reported in ER79-9.

Source: Resource figures supplied by the Geological Survey of Canada and reported in: 1986 Review and Directory, Coal Association of Canada, 1986.

Table A8-3
Coal Production - Imports and Exports - Canada

(Megatonnes)		Low Price Case								
		1985	1986	1987	1988	1989	1990	1995	2000	2005
Production	Thermal	36.5	34.9	35.2	34.6	35.6	37.7	47.7	58.8	69.7
	Metallurgical	24.4	22.6	22.6	22.6	22.6	22.6	25.0	27.6	30.5
	Total	60.9	57.5	57.8	57.2	58.2	60.3	72.7	86.4	100.2
Imports	Thermal	8.6	7.7	7.1	5.4	5.5	5.1	6.1	11.8	15.3
	Metallurgical	6.3	7.9	8.3	8.5	8.7	8.6	9.4	10.5	12.1
	Total	14.9	15.6	15.4	13.9	14.2	13.7	15.5	22.3	27.4
Domestic demand	Thermal	41.7	37.6	37.1	34.7	35.6	37.1	47.2	63.0	76.2
	Metallurgical	6.3	8.0	8.4	8.6	8.8	8.7	9.6	10.7	12.3
	Total	48.0	45.6	45.5	43.3	44.4	45.8	56.8	73.7	88.5
Exports	Thermal	4.9	5.0	5.2	5.3	5.5	5.7	6.6	7.6	8.8
	Metallurgical	22.5	22.5	22.5	22.5	22.5	22.5	24.8	27.4	30.3
	Total	27.4	27.5	27.7	27.8	28.0	28.2	31.4	35.0	39.1

		High Price Case								
		1985	1986	1987	1988	1989	1990	1995	2000	2005
Production	Thermal	36.5	34.8	35.1	34.7	35.7	38.3	49.9	60.6	70.0
	Metallurgical	24.4	22.7	22.6	22.7	22.7	22.7	24.9	27.6	30.5
	Total	60.9	57.5	57.7	57.4	58.4	61.0	74.8	88.2	100.5
Imports	Thermal	8.6	7.2	6.4	4.7	4.2	4.0	5.2	9.5	11.7
	Metallurgical	6.3	7.8	8.1	8.2	8.4	8.3	8.9	9.6	10.8
	Total	14.9	15.0	14.5	12.9	12.6	12.3	14.1	19.1	22.5
Domestic demand	Thermal	41.7	37.0	36.3	34.1	34.4	36.6	48.5	62.5	72.9
	Metallurgical	6.3	8.0	8.2	8.4	8.6	8.5	9.0	9.8	11.0
	Total	48.0	45.0	44.5	42.5	43.0	45.1	57.5	72.3	83.9
Exports	Thermal	4.9	5.0	5.2	5.3	5.5	5.7	6.6	7.6	8.8
	Metallurgical	22.5	22.5	22.5	22.5	22.5	22.5	24.8	27.4	30.3
	Total	27.4	27.5	27.7	27.8	28.0	28.2	31.4	35.0	39.1

National Energy Board

CANADIAN ENERGY

Supply and Demand 1985-2005

SUMMARY

October 1986

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SUPPLY AND DEMAND
1985 - 2005

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Foreword

The National Energy Board (NEB) was created by an Act of Parliament in 1959. The Board's regulatory powers under the National Energy Board Act include the licensing of the export of oil, gas and electricity, the issuance of certificates of public convenience and necessity for interprovincial and international pipelines and international power lines and the setting of just and reasonable tolls for pipelines under federal jurisdiction. The Act also requires that the Board keep under review the outlook for Canadian supply of all major energy commodities, including electricity, oil and natural gas and their by-products, and the demand for Canadian energy in Canada and abroad.

Since its inception the Board has prepared and maintained forecasts of energy supply and requirements and has from time to time published reports on them after obtaining the views of interested parties. The latest of these reports was issued in September 1984. It was prepared by Board staff without the involvement of Board members in a formal hearing process as had previously been the practice. In preparing the September 1984 report, Board staff took into account written submissions which had been submitted from interested parties in response to an open invitation made by the Board.

Since September 1984 the outlook for energy markets has changed reflecting changing perceptions of future energy prices, economic activity, and the availability of energy supplies. Government policies have also changed at both the federal and provincial levels in Canada, and in the United States, the major market for our exports of energy. In both countries, policy changes have tended to reduce the regulation of energy markets with potentially important consequences for energy supply and demand.

In light of these changes and the concomitant need to reappraise future prospects, the Board in March 1986 announced that its staff would update the September 1984 report. The Board stressed that this updating would be separate and distinct from any of the Board's regulatory proceedings.

For this report, the consultation process has been simplified, the objective being to benefit from the advice of interested parties at reduced cost to themselves and to the Board. Although anyone wishing to submit information was welcome to do so, the Board did not request formal submissions. Board staff prepared preliminary assumptions and results; consulted with provincial governments, industry and other interested parties; and in light of these consultations finalized the projections. We want to thank all those who generously gave of their time and expertise to this endeavour; their input was most useful.

This Summary provides an overview of the major assumptions and results of the analysis of the supply and demand for energy in Canada. The interpretations and conclusions presented are, of course, those of Board staff. Copies of this Summary or of the more detailed report can be obtained by contacting the Secretary of the Board at 473 Albert Street, Ottawa, Ontario, K1A 0E5.

Energy Units

The energy units most commonly referred to in this report are the gigajoule (GJ) and the petajoule (PJ). A 30-litre gasoline fill-up contains about one gigajoule of energy. A petajoule is one million gigajoules. A city the size of Toronto or Montreal uses a petajoule of energy for all uses (heat, light, transportation, etc.) about every 17 hours. The table on the last page of the report shows some key conversion factors we have used in compiling and converting the data used herein.

Highlights

The analysis in this report was conducted under two oil price scenarios. In *the high oil price case* world oil prices increase to $ US 27 (1986) per barrel by 1993 and then remain unchanged in real terms to 2005. In *the low oil price case* world oil prices increase to $ US 18 (1986) per barrel by 1992 and maintain that level thereafter. In both cases, we assume that natural gas prices are equivalent to the price of heavy fuel oil, retail prices differing only on account of transportation and distribution costs and taxes. We assume that electricity prices remain constant in real terms in both oil price cases. Economic growth is different in the two cases, reflecting the impact on economic growth of the different oil prices.

Demand

The use of energy in Canada is projected to grow at 1.5 percent per year in the high oil price case and 1.9 percent per year in the low, between 1985 and 2005.

Our assessment is that energy demand in Canada will continue to grow more slowly than will the economy; gains in energy conservation will occur even with oil prices below the levels of the early 1980s. The market share of oil will continue to decline to the point where oil will be used mainly for transportation, and the shares of natural gas and electricity will rise. The amount of oil used increases in both price cases over the outlook period.

Oil

Oil supply from conventional western Canadian sources is on decline. Price will determine the extent to which domestic supply is developed from the frontier areas and the oil sands, or imports are required.

In the low oil price case, substantial requirements for imported light crude oil and petroleum products occur in the latter half of the review period. In this case, large volumes of imported oil would be needed in Ontario. In the high price case oil production from the frontier areas becomes feasible, arresting the decline in productive capacity in the latter part of the period. More light crude oil supply is feasible from the upgrading of heavy crude oil, so that light crude imports are less than in the low price case. Imports could be further reduced if more heavy oil upgraders were constructed than we have allowed for.

In the high price case we project that productive capacity of heavy crude oil from conventional sources and bitumen will exhibit strong growth over the study period, while in the low price case it declines slightly. In both cases there is an excess supply of heavy crude oil over domestic requirements through to 2005.

Natural Gas

Natural gas supply from western Canada will meet domestic demand and expected exports under current licences until around 2000. In the high price case, there are more reserves additions, higher productive capacity, lower domestic demand and higher potential exports. If there were price differentiation among the industrial, residential and commercial sectors, or if the wholesale price of natural gas were to rise relative to that of heavy fuel oil, demand should decrease and supplies increase, resulting in a larger potential surplus over a longer time period.

The cost of finding new supplies in western Canada will rise over time, as quantities discovered relative to drilling activity continue to decline and an increasing share of production comes from lower productivity reservoirs. We have not included any production from frontier areas in either price scenario. The extent of frontier supply development will depend on discovery success, technological progress, and supply cost relative to market prices. Major expansion of exports would likely require such developments.

Electricity

We project growth in Canadian demand for electricity at about 2.6 percent per year over the study period. It is likely that generating capacity will be constructed in response to both domestic requirements and U.S. demand for firm power imports from Canada. Generating capacity is projected to increase from 90 gigawatts in 1984 to about 140 in 2005. Most new generating capacity will be hydro, but there will also be large increases in coal-fired and nuclear capacity.

Other Energy Forms

Pentanes plus, used primarily as a viscosity reducing agent in the transportation of heavy crude oil and bitumen, will be in short supply. In the high price case alternatives could be required as early as 1989. We project no serious supply problems for propane and butanes; ethane supply becomes inadequate in the late 1990s.

Domestic coal demand, which is mainly for thermal purposes, is projected to grow by about 3 percent per year over the review period. Most of our exports are of metallurgical coal; export growth will depend on our international competitiveness.

The use of alternative energy forms, including wood, wood wastes, and wind and solar power will increase over the projection period, but their share of total energy use is unlikely to increase because of the relatively low prices of conventional energy forms.

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National Energy Board

CANADIAN ENERGY

Supply and Demand 1985-2005

SUMMARY

October 1986

Page 6 Delete "oil" in the third sentence of the last paragraph.

Page 17 Table 5

Butanes Production in the Low Price Case in 2005 should read 6.7 rather than 5.4.

Page 18 Figure 18

Delete "Per Year" in the title of right hand vertical axis.

In this report, we provide a broad outline of what appear to us to be the major trends in Canadian energy markets, given our analysis of information currently available about the prospects for changes in major underlying factors and the consequent impact on energy supply and demand.

At the time the September 1984 Report was prepared, world energy markets were characterized by substantial excess supply of all energy commodities. The world price of oil had been declining in real terms since 1981 and there were the beginnings of a spot market for natural gas in the U.S.

Since then, the excess supply has continued and there have been major developments in oil and gas markets which have made the analysis for this report even more difficult than was the case in 1984. The factors underlying the fall in real oil prices in 1985 and early 1986 may reflect longer term supply and demand conditions. As a consequence, the world oil price projections on which this report is based are much lower than those used in 1984.

World oil prices will depend on international supply and demand for oil, and on the extent to which OPEC can exercise market power. Since there is much uncertainty about the evolution of world oil prices, our approach is to develop two projections of world oil prices. Our two projections are of sustainable, annual average prices the levels of which depend on different behavioural assumptions regarding world oil demand, the evolution and cost of non-OPEC supply, the market share falling to OPEC countries and the consequent leverage which OPEC can exercise.

The definition of the lower and higher price paths does not mean that oil prices will remain on either one of these paths year after year. The oil price will most likely fluctuate above or below each of these paths in any year, but it is not possible to forecast these fluctuations. Moreover, it is possible that the actual path could be a composite of the two projections, for example close to the low path in the earlier years, drifting up over time toward the higher path by the end of the study period.

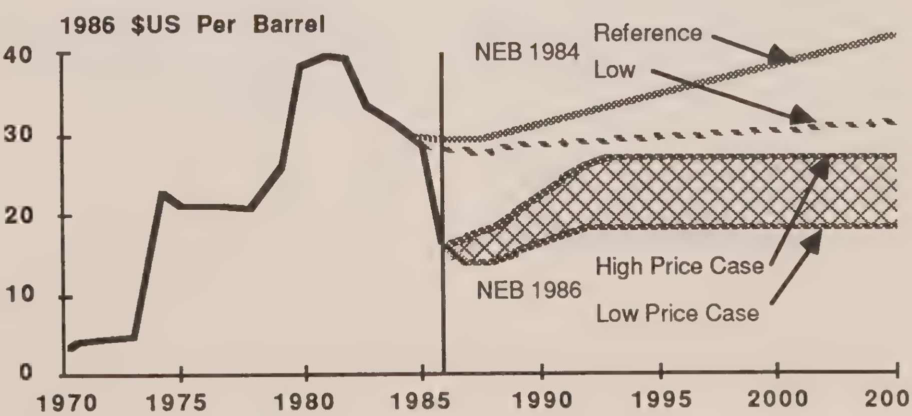
This is a different approach from that used in the September 1984 Report, in which we focussed on a reference case and a plausible range around it. The thrust of the present study is to analyze what difference it makes to energy supply and demand in Canada if world oil prices were to behave roughly as portrayed by one projection or the other.

Our two world oil price projections are shown in Figure 1. In each case, prices are projected to increase until the early 1990s and then remain constant in real terms. Figure 1 also shows that our world oil price assumptions are below those in the September 1984 Report.

The low oil price case assumes that international demand for oil will not be appreciably affected by lower prices and that there will be sufficient alternative non-OPEC energy sources available to keep the long run sustainable price from exceeding about $ US 18 (1986) per barrel.

The high oil price case assumes higher international demand for oil and more expensive, less abundant non-OPEC supplies, giving OPEC producers a larger market share and more market power. However, at $ US 27 (1986) per barrel alternative energy sources are assumed sufficient to prevent higher sustainable oil prices. We stress that our choice of $ US 27 (1986) as the maximum sustainable price in the high price case reflects a judgement about the costs of adequate alterna-

Figure 1
World Oil Prices



tive supplies - if they cost more (or less), the oil price could be maintained at a higher (or lower) level.

As oil prices influence overall economic growth and economic growth affects energy demand, we use different economic growth projections for the two oil price cases. For the country as a whole, lower oil prices generate higher levels of economic activity than do higher oil prices, because over time the positive impact of lower real oil prices on demand for non-energy goods and services outweighs the negative impact on energy export revenues and energy sector growth.

Canadian economic growth averages 3.3 percent annually from 1984 to 1990 and 2.7 percent from 1990 to 2005 in the low oil price case, compared with 2.9 and 2.4 percent per year in the same periods for the high case. The differences between the two cases reflect only the differences in projected oil prices; other factors could cause Canadian economic growth to be higher or lower than projected. In the longer term these projections are based on our expectations of growth in the labour force and improvements in productivity; in the short term, growth can exceed the longer-run potential as there are unemployed resources.

Our economic growth projections assume no further increase in the share of services in total production. This assumption is important for energy demand projections because services are less energy intensive than is goods production.

Although economic growth is projected to be higher in the low oil price case for Canada as a whole and particularly in Ontario, growth in Alberta is higher in the high oil price case, reflecting that province's higher relative concentration of energy resource production (Table 1).

There have been major moves in both Canada and the U.S. to reduce the regulation of natural gas. At the time this report was prepared the process of deregulation was still underway in both countries and it remained unclear as to how competitive markets would function, particularly in determining natural gas prices to different end users. As a result it proved particularly difficult to determine appropriate paths for natural gas prices.

Given the ability of large industrial and utility consumers to switch between natural gas and heavy fuel oil on short notice when prices warrant and assuming competitive markets, we chose to adopt a framework in which natural gas prices track heavy fuel oil prices in Canada and the U.S. In this case gas prices are the same for all users in both countries save for transportation cost differences between sources and users. Thus, we assume that residential, commercial and industrial natural gas prices will differ only by the different distribution costs for each sector and not because of natural gas price differentiation.

An alternative framework would assume price differentiation based on the value of the gas in each sector. Residential and commercial gas prices could be substantially higher and still compete with light fuel oil and electricity. In this case, and if the markets were available, the resulting higher average natural gas prices would encourage additional supplies from conventional and frontier regions.

At least in the short term it is likely that prices will reflect an amalgam of these two possibilities. As new regulatory arrangements are worked out in both Canada and the U.S., it is conceivable that the U.S., which has a larger market and therefore more scope for competition,

Table 1

Real Domestic Product by Region

(Average annual growth rates - percent)

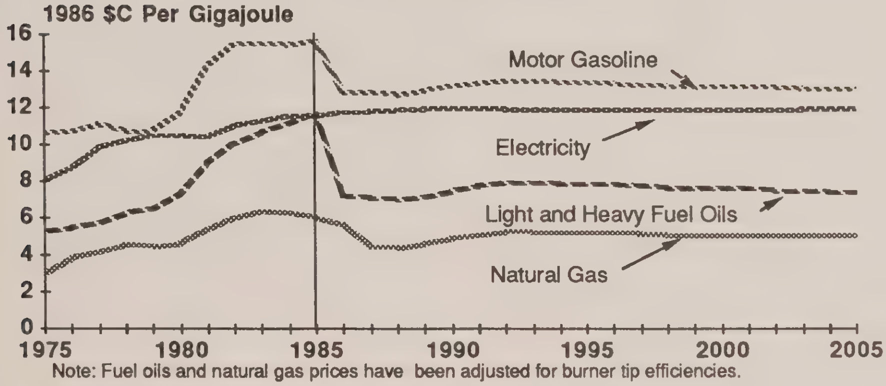
	1975-1984	1984-1990		1990-2005	
		Oil Price Case		Oil Price Case	
		Low	High	Low	High
Atlantic	2.6	2.1	2.2	2.2	2.2
Quebec	1.7	3.3	2.8	2.5	2.2
Ontario	2.4	4.0	3.3	2.7	2.4
Prairies	3.1	2.2	2.8	2.7	2.7
B.C. and Territories	3.1	3.0	2.5	2.5	2.3
Canada	2.5	3.3	2.9	2.7	2.4

Note: All numbers on this table have been rounded.

would tend more toward the "no price differentiation" situation than would Canada. We expect that U.S. gas prices will influence Canadian prices through international trade.

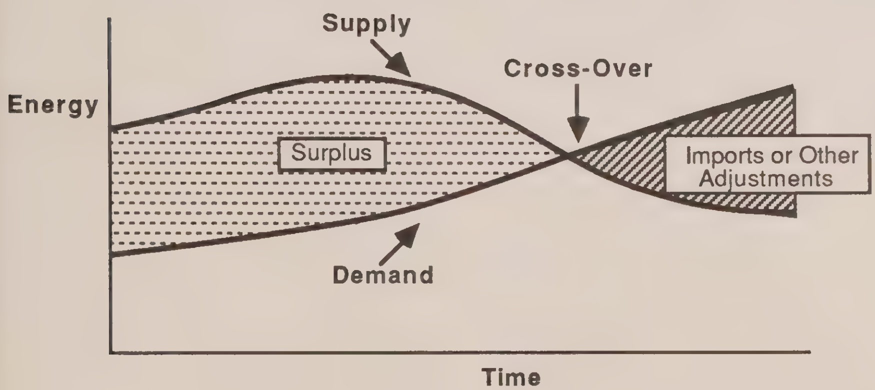
We have not examined what the impact of a price differentiation scenario would be on our supply/demand balances for natural gas; however, we recognize that there is a reasonable probability that natural gas prices will be higher than those on which we have based the analysis of this report. Thus natural gas supply and requirements could differ from our projections depending on how gas marketing evolves.

Figure 2
Average Retail Energy Prices, Canada Low Price Case



Note: Fuel oils and natural gas prices have been adjusted for burner tip efficiencies.

Figure 3
Illustration of a Supply/Demand Cross-Over



We project electricity prices to remain roughly stable in real terms over the outlook period. Rates could decline as current excess generating capacity is worked off and existing plant depreciated; however, this will be offset by the addition of new generating capacity to the rate base.

The implications of our low oil price case assumptions for average Canadian retail energy prices are shown in Figure 2. The effect of variations in world oil price is dampened at the retail level because retail prices reflect such factors as sales and excise taxes, and transmission and distribution costs, which tend to be relatively stable in real terms. Under our assumptions, fuel oil and natural gas prices increase slightly relative to the price of electricity from 1988 to about 1992, after which relative prices are constant.

We show supply/demand balances for each fuel from 1985 to 2005. Because we assume that Canadian oil and natural gas prices are determined in the international marketplace and not by supply and demand in Canada alone, it is not necessarily the case that Canadian supply and demand for oil and gas will be in balance at any time over the study period. When supply exceeds demand there is scope for additional exports. When demand exceeds supply some kind of adjustment is needed to close the gap. Either imports will increase or Canadian prices will depart from world prices so that relative fuel prices on the Canadian market will adjust, contracting demand for the fuel and increasing either its supply or the supply of substitutes (Figure 3).

Our demand analysis is based on the judgement that the heightened "energy consciousness" of consumers, which resulted from the supply disruptions and price shocks of recent years, will continue, notwithstanding the prospect of lower prices. Furthermore, to a very large extent, the substantial declines of energy intensity in recent years resulted from the development of new technology which is now embodied in buildings, machinery and other equipment, so that energy use should continue to decline relative to production as older durable goods are replaced with new, more energy efficient equipment. No doubt there are limits to the decline in energy intensity, but in our view, we are some distance from them. Lower energy prices may slow the growth of energy conservation but there are good reasons to believe that there will not be a reversal of overall energy intensity. Our assessment is that energy demand will grow less rapidly than the overall growth rate of the economy.

Our projections suggest that there will continue to be a shift off oil, even in the low price case, and that use of this fuel will be increasingly confined to the transportation sector. Concomitantly, the shares of natural gas and electricity in total energy use will increase.

Total end use demand (Figure 4) grows on average by 1.5 percent per year in the high price case and 1.9 percent in the low between 1984 and 2005. By 2005, demand in the low price case is 10 percent greater than that in the high. Both projections show steady declines in energy demand per unit of output (Figure 5), averaging 0.8 and 1.0 percent per year in the low and high price cases respectively. Output and income could vary significantly from our projections, resulting in future energy demand outside the 9 000 to 10 000 petajoule band.

The share of each consuming sector in total energy use changes only slightly over the projection period. The largest changes are in the industrial share which increases from 32 to 36 percent and in the transportation share which declines from 26 to 22 percent by 2005. Sectoral shares of energy demand do not differ between the oil price cases.

The difference in fuel shares (Figure 6) is small between the two oil price cases; substitution away from oil towards electricity is more pronounced in the high oil price case. The increase in the share of natural gas is similar in both cases. By 2005, oil's share of total end use demand will be about one-third, down from 42 percent in 1984; that of natural gas 30 percent, up from 26 percent in 1984; and that of electricity almost 25 percent, up from 19 percent in 1984.

Figure 4

Total End Use Energy Demand

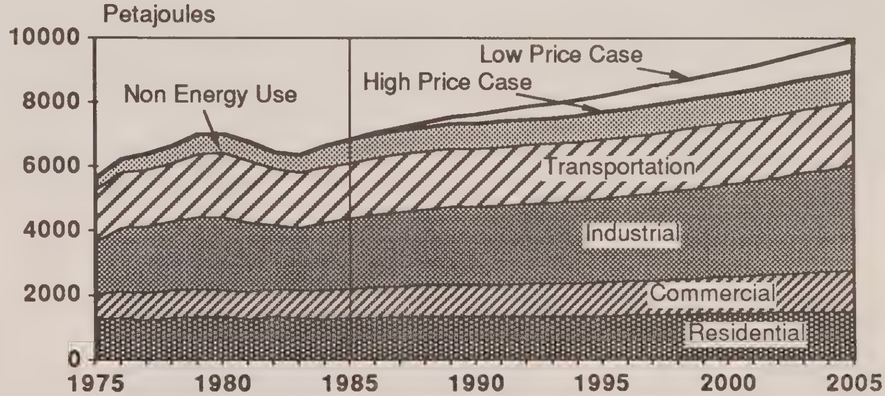
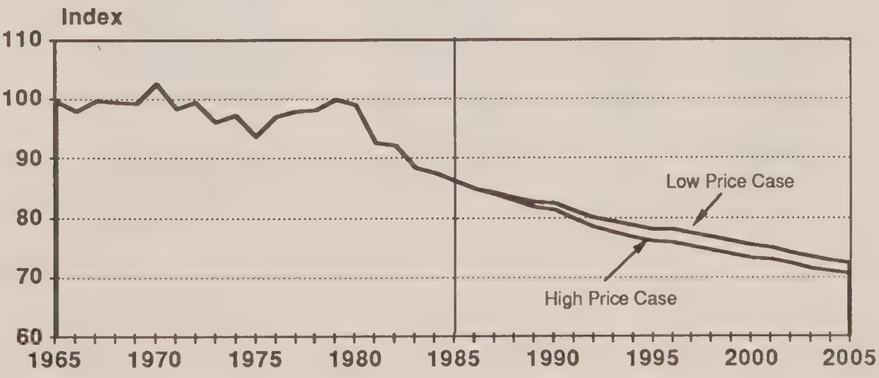


Figure 5

End Use Energy Demand per Unit of Real GNP 1965=100



Alternative energy will satisfy about the same share of total demand as it did in 1984, as the oil price outlook limits the opportunities for economic substitution of conventional energy.

Residential end use energy demand increases from 1325 petajoules in 1984 to 1648 and 1523 in 2005 in the low and high oil price cases respectively. This is an average annual increase of about 1 percent in the low price case and 0.7 in the high. The lower growth in the high price case reflects our lower outlook for real disposable income in that case, and the reaction to the higher energy prices. The total number of households increases in both cases, but energy demand per household declines from 152 gigajoules in 1984 to 141 and 131 by 2005 in the low and high oil price cases respectively. (It was 196 gigajoules per household in 1973.)

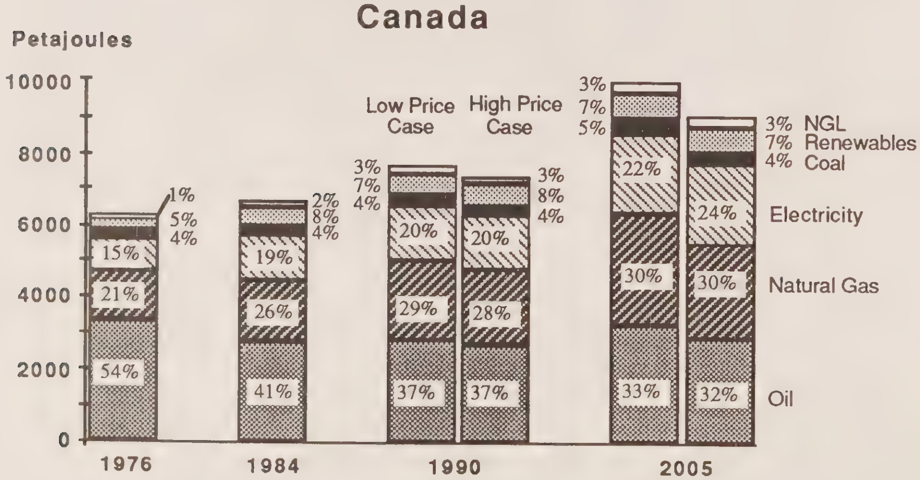
Energy use in the commercial sector increases from 872 petajoules in 1984 to 1420 and 1269 in 2005 in the low and high oil price cases respectively, as the effect of increases in commercial real domestic product outweigh declines in intensity of energy use.

Industrial energy use accounts for about 30 percent of total end use energy demand. It depends crucially on the size of industrial output, the share of output held by energy-intensive industries and the rate of energy-saving technological change. We expect industrial output to grow at over 2.5 percent per year over the study period; the share of energy-intensive industries such as pulp, paper, refining, smelting and mining in total industrial output declines very little. The decline of energy intensity which began in the 1970s continues but at a slower pace in the 1990s and beyond. Industrial end use demand increases from 2104 petajoules in 1984 to 3629 and 3277 in the low and high oil price cases respectively.

Petrochemical feedstock requirements increase in both price cases from 484 petajoules in 1984 to 686 in 2005. We expect that about half of this increase will be taken up by natural gas and a quarter by ethane. Our projections include the construction, mainly in Alberta, of eight ammonia plants which use natural gas as feedstock and one ethylene plant which uses ethane and natural gas as feedstock. Use of oil for feedstock will decline from about 130 petajoules in 1985 to 100 by 2005. There is no difference in our projections between the two oil price cases, as we assume that the Canadian petrochemical industry will be internationally competitive in both cases.

In 1984, road, rail, air and marine transportation accounted for 26 percent of total end use demand and 62 percent of end use oil demand. Road transport is the largest component, accounting for 80 percent of transportation energy demand in 1984. Transportation energy demand increases by close to 1.5 percent per year in the low price case and less than 1 percent in the high price case over the study period so that by 2005 transportation is projected to account for about 22 percent of end use oil demand. Continued but smaller improvements in the energy efficiencies of vehicles are more than offset by an increase in the number of vehicles on the road. Our projections of energy efficiency improvements in vehicles are lower than those included in our September 1984 Report because the oil price projections are lower.

Figure 6
End Use Demand by Fuel
Canada



The largest component (92 percent) of total (or primary) oil demand consists of end use requirements for refined products consumed directly by the residential, commercial, industrial and transportation sectors. Oil used to generate steam and electricity, requirements of the energy supply industry to produce and transport oil products, and liquefied petroleum gases produced and used by refiners are also included in primary demand.

Between 1984 and 2005 primary demand for oil is projected to increase from 3100 petajoules to 3800 and 3200 in the low and high oil price cases respectively (average annual growth rates of 1.0 and 0.2 percent). By 2005 the difference between the low and high oil price cases is 15 percent. This is mainly because of the difference in transportation demand, the largest component of total primary oil demand, which differs in the two cases by about 300 petajoules in 2005.

Canada has a large oil resource base part of which will be used to meet future demand. Ninety percent of this resource base is bitumen; conventional crude oil constitutes only ten percent, of which half is located in western Canada and half in the frontier regions. The fraction of the resource base which is economically recoverable constitutes reserves.

Established reserves of conventional crude oil at year-end 1984 amounted to 741 million cubic metres (613 million cubic metres of light and 128 of heavy), about 28 exajoules (Figure 7). Reserves have remained essentially unchanged over the last four years because produced reserves have been replaced by reserves additions.

Projected reserves additions of conventional crude oil (light and heavy) for the period 1985 to 2005 amount to approximately 460 and 610 million cubic metres in the low and high oil price cases respectively. For light oil only, we project reserves additions of 325 and 425 million cubic metres in the low and high price cases respectively. Of these increases, some 160 and 190 million cubic metres respectively are expected to result from the application of enhanced oil recovery techniques in oil pools discovered to date, and the remainder from future drilling activity.

Given our price projections there are relatively few major projects (including those related to frontier supplies) expected over the study period. In the high price case, we project new production of light crude oil from the development of Hibernia, the Beaufort Sea and limited upgrading of heavy crude oil and bitumen. The only new major project included in the low oil price scenario is the heavy crude oil upgrader now under construction in Saskatchewan. Table 2 sets out for both price cases the major projects which we have included in our projections.

Figure 7
Reserves of Conventional Crude Oil Conventional Areas
Millions of Cubic Metres

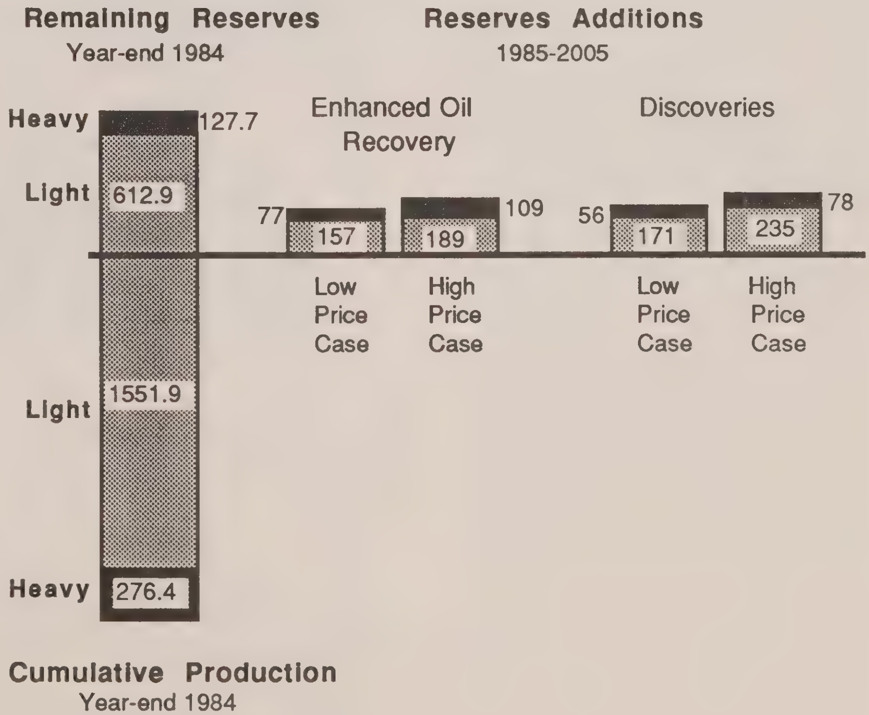


Table 2
Timing of Major Projects

	Size [a]	Start-up Year Low Price Case	Start-up Year High Price Case
Oil Sands Mining Plants			
Expansion of Syncrude	2.5	--	1991
Upgraders			
Co-op	8.0	1988	1988
Other	8.0	--	1995
Other	8.0	--	1999
Frontier Areas			
Hibernia	17.5	--	1995
Beaufort Sea	17.5	--	1996

[a] Thousands of Cubic Metres per Day.

Productive capacity from reserves additions of conventional light crude oil is insufficient to replace production during the outlook period in both price cases (Figure 8). In the low price case the productive capacity of light crude oil and equivalent in 2005 is only 40 percent of the 1985 level. In the high price case, with new supplies from two additional regional upgraders and from the frontier regions, the productive capacity of light crude oil and equivalent declines to 63 percent of the 1985 level in 2005.

It is difficult to assess the extent to which bitumen or heavy crude oil will be upgraded to synthetic light crude. The oil sands resource is known and recoverable quantities are very large. The issue is whether expected price/cost relationships are such as to make the production of synthetic light crude economically viable. Oil sands mining plants (such as Syncrude and Suncor) are large scale operations subject to substantial economic risk. Our estimates of construction and operating costs suggest that, in our high price case, new plants are in the range of being economically viable; however, there is very little margin for error in either the cost estimates or revenue expectations. Because these plants require very large up-front investment and considerable lead time, and because there is much uncertainty about both ultimate costs and oil prices, we do not assume that major new capacity will be constructed. However, cost reduction, improved technology and a sustained period of attractive oil prices could stimulate investor confidence and lead to the construction of new or expanded oil sands mining plants during the next twenty years.

The prospects for upgrading of conventional heavy crude oil and bitumen produced by in situ methods are more favorable and, in the high price case, we have allowed for the construction of two upgraders in addition to the one now under construction in Saskatchewan. As in the case of oil sands mining plants, changing perceptions of risk and improved price/cost relationships could result in more upgrading capacity being constructed over the study period than we have allowed for.

Technological development may improve the economic feasibility of other supply sources, such as liquefaction of coal or the co-processing of coal and oil.

Figure 8
Supply of Domestic Crude Oil and Equivalent
Low Price Case

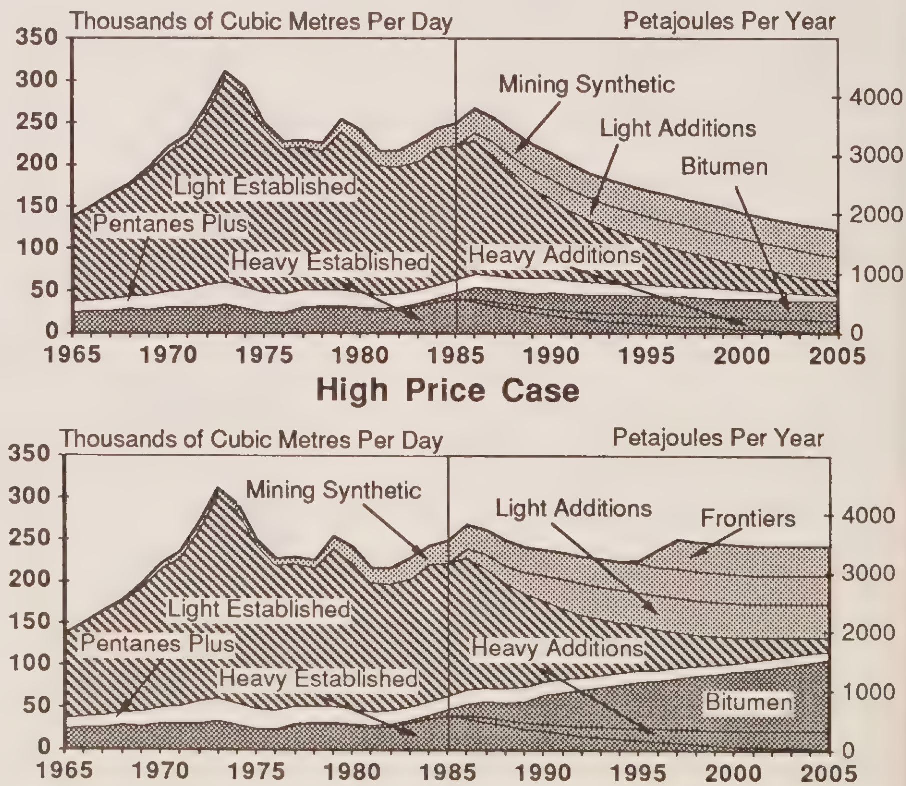
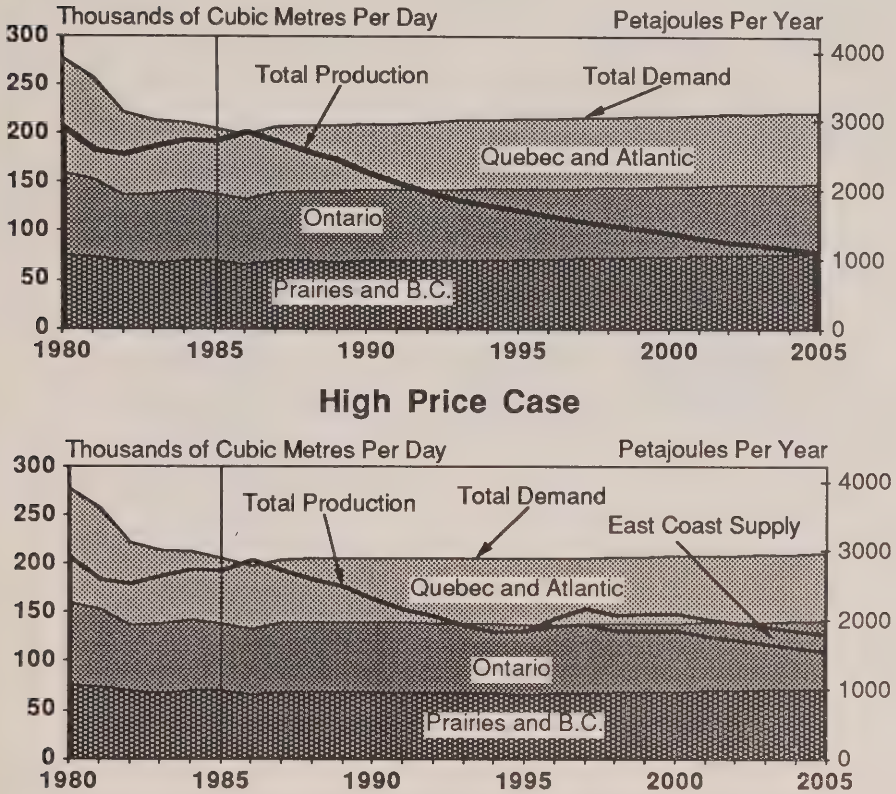


Figure 9
Supply and Demand - Light Crude Oil
Low Price Case



Canada's requirements for light crude oil grow over the review period by 16 thousand cubic metres per day to 223 thousand cubic metres per day in the low price case and by 5 thousand cubic metres per day to 212 thousand cubic metres per day in the high price case. As a result Canada will become increasingly dependent on oil imports (Figure 9). In the low price case, imports by 2005 could be as much as 142 thousand cubic metres per day (some 64 percent of total domestic light crude requirements). In the high price case the import requirement is less, 84 thousand cubic metres per day (40 percent of total domestic light crude oil requirements).

Montreal refiners using western Canadian crude oil would be the first to feel the effects of declining domestic production. Deliveries on the Sarnia to Montreal portion of the Interprovincial pipeline could cease in the early 1990s.

Ontario refiners could also be importing some of their light crude requirements beginning as early as 1992. Imports into Ontario reach 70 thousand cubic metres per day in the low price case, and 32 thousand cubic metres per day in the high price case by the end of the study period. The increasing demand for imports into Ontario could be met by shipments of offshore imported oil through pipelines in the U.S. midwest and/or through reversal of the Sarnia to Montreal pipeline.

Heavy crude oil supply is expected to increase substantially in the high price case because of the relatively favourable supply cost of bitumen from in situ projects. In the low price case, we expect supply to decline slightly with development of only the better quality bitumen reservoirs associated with projects currently under construction. In 2005 the productive capacity of heavy crude oil is 41 thousand cubic metres per day in the low price case compared to 55 thousand cubic metres per day in 1985. In the high price case, productive capacity reaches 114 thousand cubic metres per day in 2005 because of the extensive bitumen development.

Domestic refinery demand for heavy crude oil is not expected to exhibit strong growth and will be much less than available supply throughout the outlook period (Table 3). The excess supply will likely continue to be sold to refiners in the U.S. In the low price case exports decline from 40 thousand cubic metres per day in 1985 to a potential of 22 thousand cubic metres per day by 2005. In the high price case potential exports could be 95 thousand cubic metres per day by 2005 provided new markets are available.

Table 3

Heavy Crude Oil
Supply and Demand Balance

		Low Price Case		High Price Case	
	1985	**1995**	**2005**	**1995**	**2005**
	(Thousands of cubic metres per day)				
Domestic Supply [a]	55	47	41	94	114
Domestic Requirements	15	17	19	17	19
Excess Supply (Potential Exports)	40	30	22	77	95

Note: The numbers in this table have been rounded.

[a] Domestic supply includes diluent but excludes heavy crude oil used in regional upgraders.

Figure 10

Reserves of Marketable Natural Gas Conventional Areas

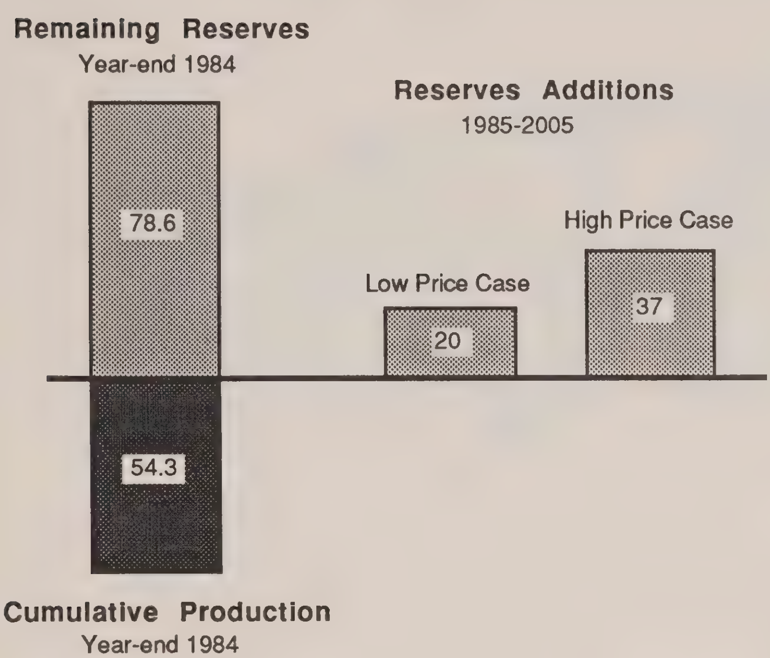
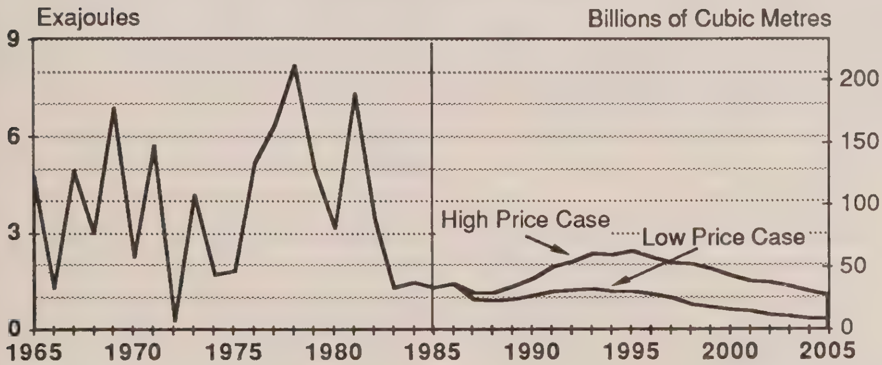


Figure 11

Marketable Natural Gas Reserves Additions Conventional Area



Note: The abnormally high reserves additions shown for 1976 and the several years following appear to have resulted from a combination of escalating drilling levels and the availability of an inventory of drilling prospects which had been uneconomical at prices in effect earlier.

Total use of natural gas in Canada is projected to grow from 1950 petajoules in 1984 to 3300 and 2900 petajoules in 2005 in the low and high oil price cases respectively. The corresponding average annual growth rates are 2.5 and 2.0 percent per year.

Canada has substantial established reserves and the potential for large reserves additions from both conventional and frontier areas.

Established reserves of natural gas at year-end 1984 included some 79 exajoules mainly in western Canada (Figure 10), 6 exajoules in the Mackenzie Delta area and 12 exajoules in the Arctic Islands. A sizeable portion of the western Canadian reserves is in small pools which have never been placed on production; their reserves may be overestimated.

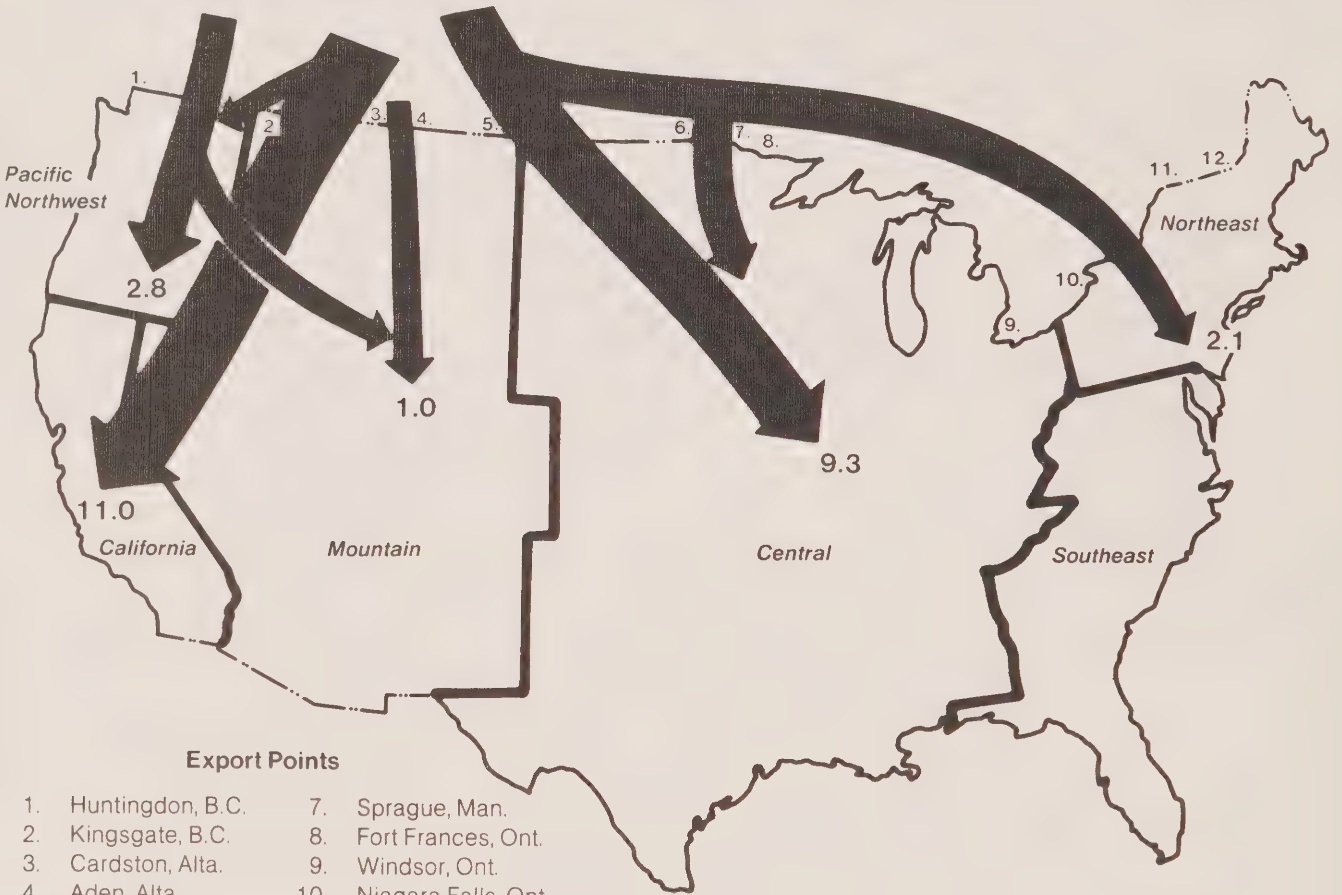
Our projections of reserves additions (Figure 11) are based on estimates of future finding rates and drilling levels. In the high price case, we project 37 exajoules of reserves additions during the review period, about the same as projected for the same period in the September 1984 Report reference case. In the low price case, only 20 exajoules of reserves additions occur.

In neither case do we include production from frontier reserves. Both the Polar and Venture projects have facility applications before the Board, but neither contains the supply information required for evaluation. Because of the uncertainty of the size of the reserves available to support these projects, we do not include supply from them.

Productive capacity from the western Canadian reserves currently under contract declines throughout the forecast period as a result of reservoir depletion. As we move far-

Figure 12

United States Regional Natural Gas Markets and Canadian Export Flows (1985)[1]



Export Points

1. Huntingdon, B.C.
2. Kingsgate, B.C.
3. Cardston, Alta.
4. Aden, Alta.
5. Monchy, Sask.
6. Emerson, Man.
7. Sprague, Man.
8. Fort Frances, Ont.
9. Windsor, Ont.
10. Niagara Falls, Ont.
11. Cornwall, Ont.
12. Philipsburg, Que.

1 Figures shown by the arrows are 1985 export volumes in billions of cubic metres.

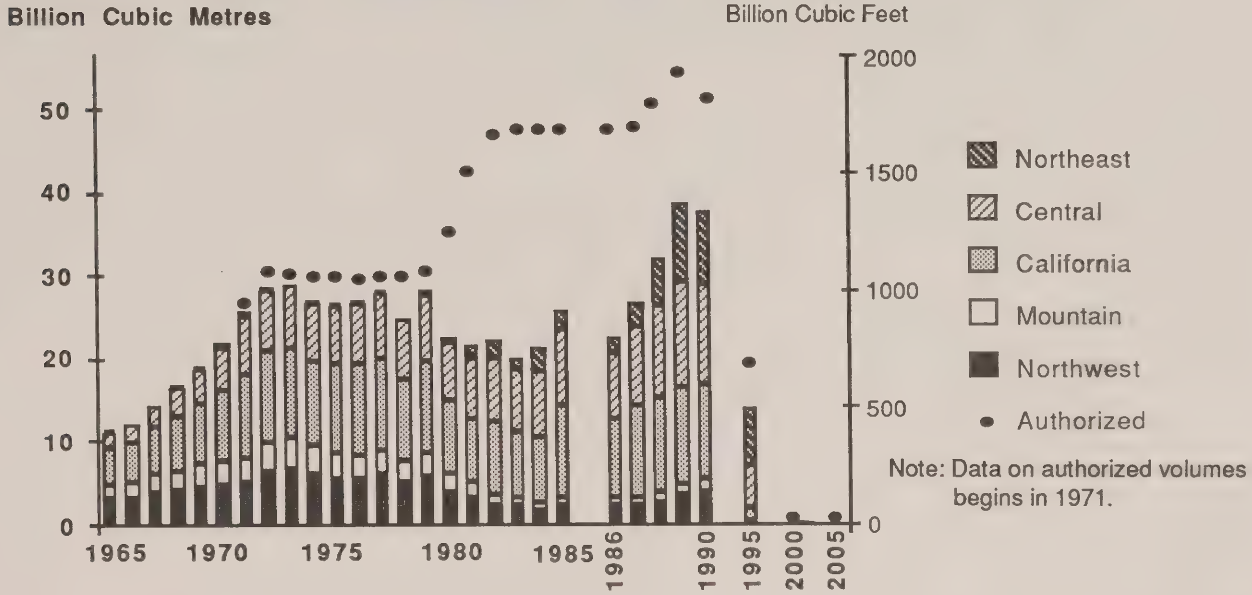
ther into the review period, productive capacity from reserves additions will account for an increasingly larger proportion of total productive capacity. Projected productive capacity is lower in total in both price cases than the reference case projection in the September 1984 Report, reflecting the lower natural gas prices assumed in the current study.

Productive capacity could be larger than projected if natural gas prices were higher than we assume. With higher prices and improved cash flow to the industry, additional drilling would be likely, resulting in higher reserves additions. Poorer quality reserves and higher cost supplies could become profitable to produce, increasing ultimate potential.

Canadian natural gas exports rise from their 1985 level (Figure 12) of 26 billion cubic metres (about 1 exajoule, 5.4 percent of the American natural gas market) to approximately 38 billion cubic metres (almost 1.5 exajoules, 7.7 percent of the American market) by 1990 (Figure 13). This increase depends upon completion of the move to market-oriented pricing in Canada, competi-

Figure 13

Natural Gas Exports Under NEB Licence



Note: Data on authorized volumes begins in 1971.

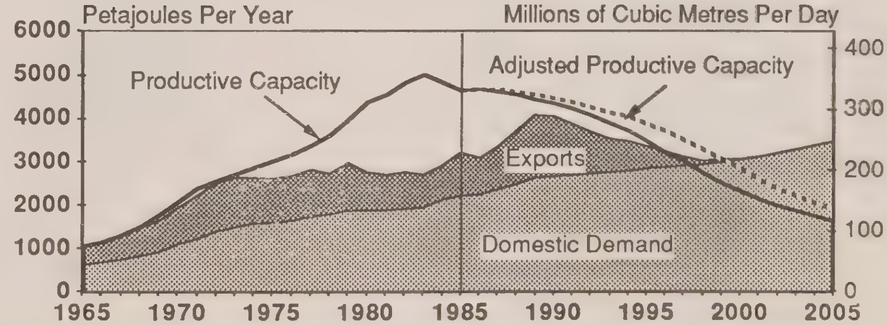
tive Canadian prices, the elimination of the U.S. gas deliverability surplus and access by Canadian gas to United States interstate pipelines.

Although we do not project natural gas exports beyond currently authorized volumes, in the longer term U.S. demand for Canadian natural gas is expected to be strong. To maintain high levels of exports beyond the early 1990s would likely require production from frontier sources.

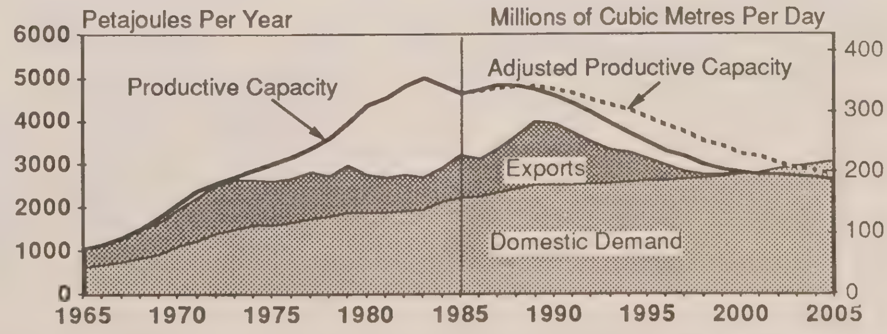
Productive capacity from western Canada (adjusted for carry forward of any unused capacity from previous years) satisfies total demand for natural gas in the low price case up to and including the year 1999, and in the high price case to 2002 (Figure 14). Beyond those dates supply and demand balance will have to be achieved by price adjustment, new sources of domestic supply, imports or fuel substitution.

Figure14

Natural Gas Supply and Demand
Conventional Areas
Low Price Case



High Price Case



In 1984, the total Canadian demand for electricity was 386 terawatt hours. This demand is projected to grow steadily by about 2.6 percent annually to a level of about 660 terawatt hours in 2005 for both oil price outlooks. Total electricity demand is similar in the two price cases because in the high oil price case electricity captures a larger share of a smaller energy market. In Alberta, Newfoundland and Nova Scotia higher electricity demand occurs in the high oil price case than in the low, primarily because economic activity is higher in those provinces when oil prices are high.

In response to the increasing domestic demand and to projected potential for additional firm sales to the U.S., generating capacity is projected to grow from 90 gigawatts in 1984 to about 140 and 145 gigawatts by 2005 in the high and low oil price cases respectively.

Over the study period, hydro continues to supply 60 to 65 percent of total requirements, the balance coming from fossil fuels (primarily coal) and nuclear (Figure 15). Nuclear generation accounted for about 12 percent of Canadian production in 1984; by 2005, this grows to about 18 percent. In Ontario nuclear generation accounts for over 60 percent of provincial generation by 1990, but this decreases to about 55 percent by 2005.

In 1984, exports of electricity to the United States were about 40 terawatt hours, of which about one quarter was sold on a firm basis and the balance as interruptible energy. We project that exports will increase to roughly 50 terawatt hours per year by 1990 and remain at approximately that level until 2005, by which time nearly one half of all exports may be on a firm basis (Figure 16). These projections include potential quantities planned for export by provincial utilities but not yet licensed by the National Energy Board. Their inclusion as potential exports in this study has of course no bearing on whether or not they will be licensed.

Given adequate lead time, Canadian utilities could accommodate increases in demand well in excess of the levels we have projected. For this reason, we do not expect any supply shortfalls or major price increases within the study period. Table 4 shows our projections of generating capacity by fuel type.

Figure 15

Production of Electricity

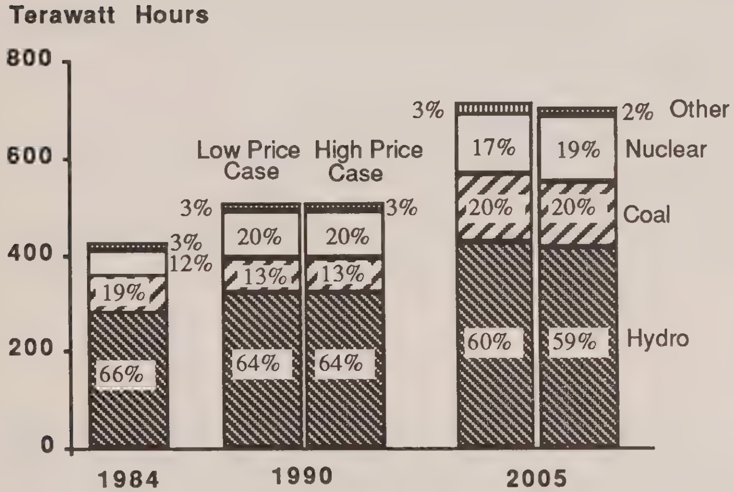


Figure 16

Exports Of Electricity

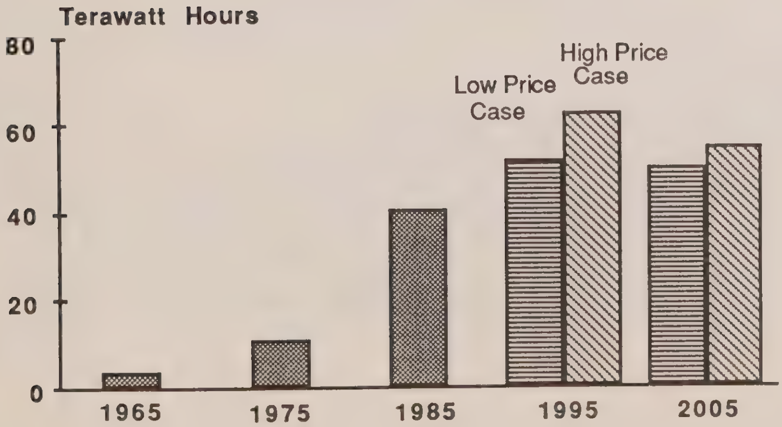


Table 4

Electricity Generating Capacity by Fuel Type

Electricity Production, Gigawatts (GW)

	1984		1990				2005			
			Low Price Case		High Price Case		Low Price Case		High Price Case	
	GW	Percent	GW	Percent	GW	Percent	GW	Percent	GW	Percent
Coal	16.1	18	19.1	19	19.1	19	28.7	20	29.2	21
Hydro	55.0	60	58.4	57	58.4	57	81.5	56	77.2	55
Nuclear	7.7	8	13.5	13	13.5	13	18.7	13	18.7	13
Oil and Natural Gas	9.3	11	8.5	9	8.7	9	13.5	9	11.7	9
Other	2.3	3	2.5	2	2.5	2	2.7	2	2.7	2
Total	90.4	100	102.0	100	102.2	100	145.1	100	139.5	100

Note: The numbers in this table have been rounded.

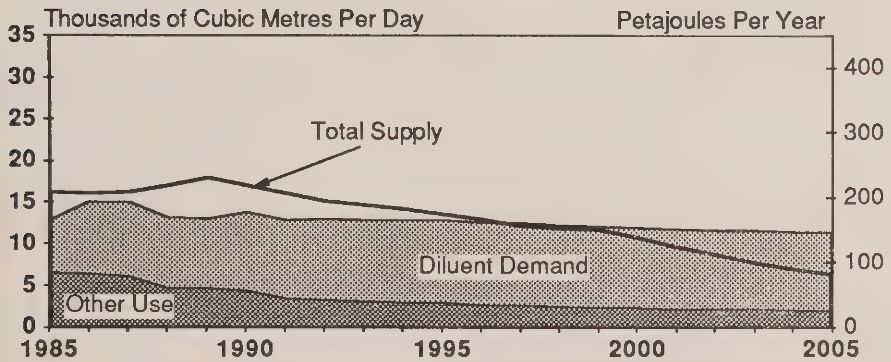
Table 5

Natural Gas Liquids Production and Demand

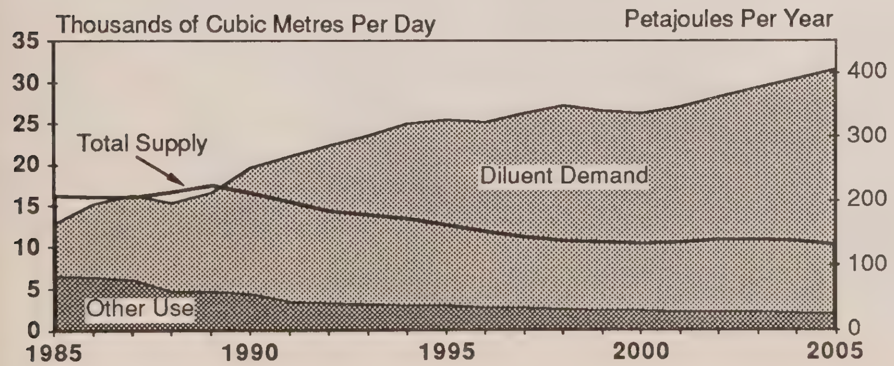
			Low Price Case		High Price Case	
		1985	**1995**	**2005**	**1995**	**2005**
		(Thousands of Cubic Metres per Day)				
Ethane	Production	17.5	23.6	8.6	22.4	13.6
	Demand	14.1	16.9	18.8	22.4	18.8
Propane	Production	19.9	19.8	10.8	18.4	15.4
	Demand	12.5	13.9	15.4	15.7	15.9
Butanes	Production	11.9	11.4	5.4	10.6	9.2
	Demand	5.1	6.0	6.1	6.2	5.6

Note: The numbers in this table have been rounded.

Figure 17
Pentanes Plus Supply and Demand
Low Price Case



High Price Case



Natural Gas Liquids

Natural gas liquids consist of ethane, propane, butanes and pentanes plus. These hydrocarbons are extracted from natural gas streams; propane and butanes are also produced in the refining of crude oil. About three-quarters of the production comes from gas plants.

Each natural gas liquid is used differently because of its unique characteristics. Ethane is used in Canada mainly as a petrochemical feedstock in the manufacture of ethylene, and as a fluid injected into crude oil reservoirs to increase recovery. Propane has a variety of end uses including cooking, space heating, crop drying and as motor fuel. Like ethane, propane is also used as a petrochemical feedstock and to increase recovery from crude oil reservoirs. Butanes are used mainly in gasoline manufacturing, either in the refining processes or as a blending component, and as a petrochemical feedstock.

Pentanes plus is used as a viscosity reducing agent for pipelining conventional heavy oil and bitumen and as a refinery feedstock.

NGL production declines in the 1990s in both oil price cases mainly because of the projected decline in natural gas production.

Supplies of ethane are more than sufficient to meet domestic demand until the late 1990s (Table 5); propane until 2002 in the low price case and through 2005 in the high price case; butanes throughout the projection period in both price cases; and pentanes plus until 1996 in the low price case but only to 1988 in the high price case (Figure 17).

Coal

Recoverable reserves of coal are estimated at over 6000 megatonnes (150 exajoules), about 100 times Canada's annual coal production. Of these reserves almost two-thirds are located in British Columbia and Alberta and almost 90 percent are estimated to be recoverable by surface mining methods.

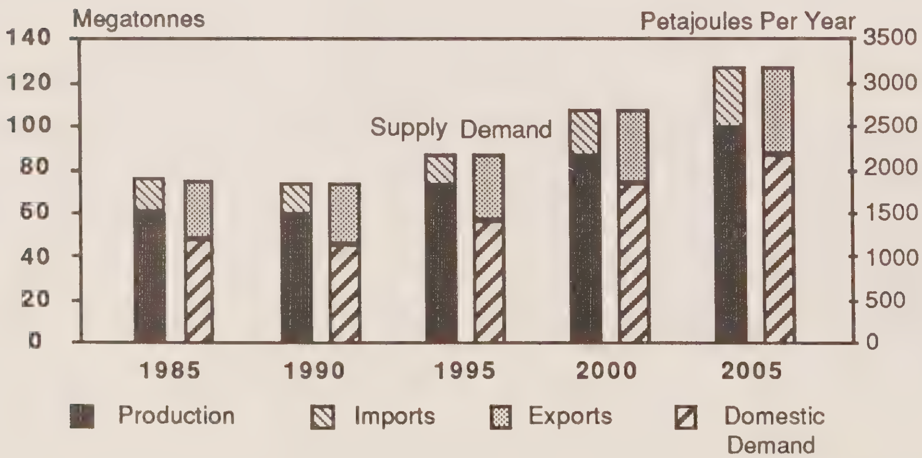
Domestic demand for coal is projected to grow from 48 megatonnes in 1985 to 87 megatonnes in 2005 in the low oil price case and 84 in the high. About three-quarters of Canadian coal requirements is for thermal coal used to generate electricity, mainly in Ontario and Alberta. The estimate of Ontario's coal demand is based on the assumption that Ontario Hydro will add coal generation after Darlington.

Coal exports in 1985 were 27 megatonnes (45 percent of production). These exports were 82 percent metallurgical coal; Japan was the largest customer, accounting for 68 percent of our coal exports. Exports are projected to grow to 39 megatonnes by 2005 but are subject to major market uncertainties, as there is currently excess capacity world-wide. Figure 18 shows supply and demand for coal in the domestic and export markets in the low price case; the pattern is similar in the high price case.

In 1985 imports were 15 megatonnes, mostly to Ontario. Thermal coal, used by Ontario Hydro, accounted for 57 percent of total imports. Coal imports grow from 15 megatonnes in 1985 to 27 in the low oil price case in 2005 and 23 in the high. These projections assume that western coal remains generally uncompetitive in Ontario with imports from the U.S. Imports could be lower than anticipated if the transportation cost disadvantage of western Canadian coal were offset by the high cost of controlling sulphur emissions from imported coal.

In sum, coal production is expected to remain constant at about 60 million tonnes per year until the early 1990s in both the high and the low price cases after which it increases to about 100 million tonnes per year in 2005.

Figure 18
Coal Supply and Demand in Canada
Low Price Case



Alternative Energy Sources

Alternative energy sources include hog fuel and pulping liquor, wood, solar, wind and municipal solid waste. They accounted for about 8 percent of total Canadian end use energy demand in 1984; however, in British Columbia where the forest industry makes extensive use of wood waste, they accounted for 23 percent, and in the Atlantic region, where wood is used to a large degree for residential heating, for 15 percent.

The degree of penetration of alternative energy sources depends on their costs, relative to the costs of other energy forms. As our present outlook is characterized by slower real price growth for conventional energy, we are now less optimistic about penetration of alternative energy than we were in the September 1984 Report.

In our low and high oil price cases we expect renewable energy forms to account for 6 and 7 percent respectively of end use energy demand in 2005, about the same proportion as in 1984.

Technological developments which reduce the cost of these energy forms could result in their gaining a larger share of total energy demand than we have projected under our energy price assumptions.

Regional considerations - particularly the available alternative energy sources - may favour development and use of renewable and other nonconventional energy forms in some regions over others.

Canada is one of the few OECD countries to have produced more energy than it has consumed over the last decade. In 1985 Canada had net exports of about 2300 petajoules (valued at $10.7 billion), one-fifth of its total primary energy production.

Whether we will continue to produce more energy than we consume depends critically on oil prices. If oil prices are high, energy production is projected to continue to exceed requirements; however, if oil prices remain low, production will decline and eventually fall below our total energy requirements. The difference in the two cases is attributable more to the impact of prices on the supply of oil and gas than to its effect on demand. While there is a difference of only 10 percent in energy demand between the two price cases, the difference in supply is 30 percent (Figures 19 and 20).

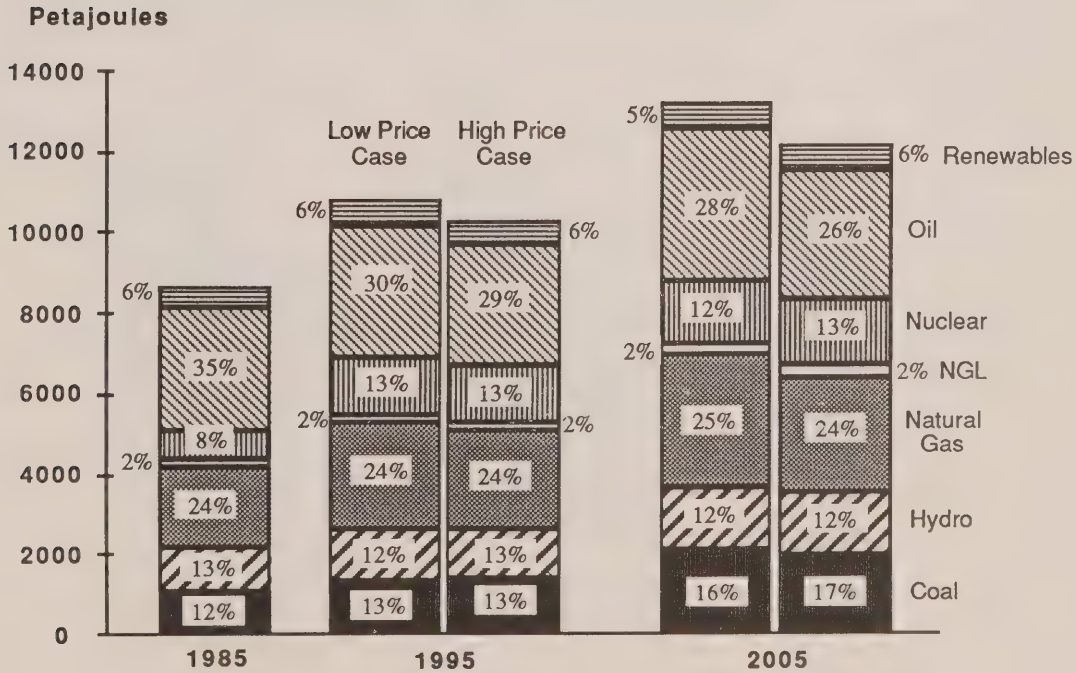
Our projections (Table 6) suggest that for both cases Canada will continue to be a net energy exporter over the next ten years. In the low price case, Canada becomes a net importer of energy by the end of the study period; in the high price case the potential exists for continuing substantial net exports of energy through 2005.

In both price cases it is probable that Canada will become increasingly dependent on imports of light crude oil as time goes on. This dependency could be reduced substantially in the high price case if more regional heavy oil upgraders were to be constructed than we have allowed for.

Canada currently is a net exporter of petroleum products. This is likely to reverse in the 1990s in the low price case where substantial imports of petroleum products appear to be required by 2005. However, in the high price case, Canada continues to be a net exporter of petroleum

Figure 19

Comparison of Primary Energy Demand Projections



Note: Hydro electricity converted to PJ using 3.6 PJ/TW.h
Nuclear electricity converted to PJ using 12.1 PJ/TW.h

products (albeit in progessively decreasing quantities) throughout the review period.

An excess supply of heavy crude oil is likely to continue in both scenarios. The excess supply decreases over the study period in the low price case but increases substantially in the high price case.

For natural gas, we project that, in both price cases, supplies from the conventional areas will meet demand, including exports under existing authorizations, until 2000 or beyond. The projected cross-overs are an indication that some adjustment will be required to balance supply and demand, perhaps including an increase in the price of natural gas relative to oil. In Table 6, the numbers shown for natural gas include only projected exports under current licence authorizations. Natural gas exports could be larger depending on the retail gas prices which emerge as deregulation proceeds, on the relative wholesale prices of gas and oil, on the rate of development of new supplies, and on U.S. import requirements and prices.

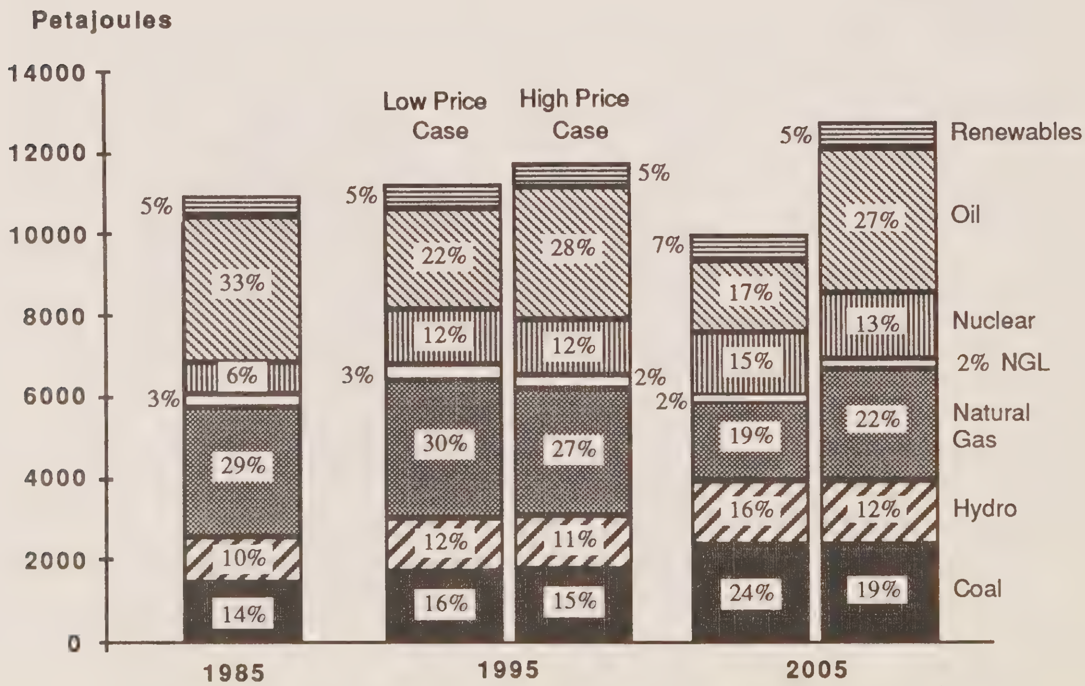
Canada is likely to continue to be a net exporter of metallurgical coal and of electricity in both oil price cases. The extent of our exports will depend on our production and transportation costs relative to those of other countries.

Among OECD countries, in 1984 Canada was the 9th largest in population, 7th in gross domestic product, 5th in primary demand for energy, and second in energy production. On a per capita basis, Canada was the third largest energy consumer in 1984, slightly below the United States.

On the basis of energy use per unit of Gross Domestic Product, Canada ranked fourth. Canada's energy efficiency improved by just over half a percent per year between 1973 and 1984, but this improvement was below that experienced in most other OECD countries.

Figure 20

Comparison of Primary Energy Production Projections



Note: Hydro electricity converted to PJ using 3.6 PJ/TW.h and nuclear electricity converted to PJ using 12.1 PJ/TW.h.

Table 6

Energy Balances

(Petajoules)

	Net Energy Exports (Imports)			Excess Supply (Demand) [c]			
				Low Price Case		High Price Case	
	1965	1975	1985	1995	2005	1995	2005
Coal	(422)	(146)	365	382	281	416	399
Electricity [a]	–	11	147	188	180	227	198
Natural Gas	430	1040	990	526 [d]	(1551)	526 [d]	(310)
NGL	34	147	163	153	(105)	71	8
Petroleum [b]	(567)	(111)	623	(945)	(2132)	156	185
Total	(525)	941	2288	304	(3327)	1396	480

-- Too small to be expressed.

Notes: The numbers in this table have been rounded.

[a] Hydro and nuclear electricity converted to PJ using 3.6 PJ/TW.h. Electricity excludes exchanges involving no net imports or exports.

[b] Petroleum includes crude oil and refined petroleum products, but excludes exchanges involving no net imports or exports.

[c] Excess supply is indicative of potential exports. Excess demand is indicative of a requirement which may be met by one or a combination of: importing, substituting other energy sources, and/or developing larger domestic supplies. For the latter two forms of adjustment to occur, relative prices would have to change to provide the necessary incentives to alter consumption and production.

[d] Includes only projected exports under existing licences.

Concluding Comments

The major conclusion of our report is that conventional oil and gas supply sources will not be adequate to meet Canada's future requirements.

The existence of frontier and unconventional hydrocarbon resources which could be developed to continue to provide Canada with energy security is not in question; the issue is whether these resources can be economically developed given prospects for future price/cost relationships. If our price paths were to prevail, given the present state of technology, and assuming that our supply cost estimates are generally valid, it is not certain that these resources would be developed on a large scale.

We have noted the uncertainties about the prospects for world oil prices and natural gas prices. There are also uncertainties about the prospects for costs of development and production of Canadian resources. Technological progress will be made which should reduce supply costs over time. It may also be true that our cost estimates, based as they are largely on the experience of a period of severe inflation, have overestimated the potential costs of future energy supply, thereby leading us to underestimate its availability.

Energy security can also result from conservation. Our demand analysis shows that, given time and the appropriate pricing signals, there is scope for continuing conservation and substitution among energy forms. However, there are factors which could interfere with the adjustment process. For example, it is not certain that over the next twenty years the pricing system will necessarily deliver appropriate signals to producers and consumers; and there could be disruptions in world markets so severe that price changes alone may not be able to equilibrate demand and supply in the short term.

Substitution of one energy source for another and energy conservation will occur in the future as they have in the past. To determine the desirability of self-sufficiency in any energy form would require an assessment of the net costs or benefits of such a goal, a task beyond the scope of this study.

Abbreviations of Names, Terms and Units

"NEB" or "the Board"	National Energy Board
Act	The National Energy Board Act
September 1984 Report	*Canadian Energy Supply and Demand 1983-2005 (Technical Report and Summary Report)*, NEB, September 1984
High (Oil) Price Case	See Figure 1
Low (Oil) Price Case	See Figure 1
OPEC	Organization of Petroleum Exporting Countries
OECD	Organization for Economic Cooperation and Development
NGL	Natural gas liquids (ethane, propane, butanes and pentanes plus)
$ C	Canadian dollars
$ US	United States dollars
J	joule
PJ	petajoule
EJ	exajoule
kW	kilowatt
MW	megawatt
GW	gigawatt
kW.h	kilowatt hour
MW.h	megawatt hour
GW.h	gigawatt hour

Prefixes

Prefix	**Multiple**	**Symbol**
kilo	10^3	k
mega	10^6	M
giga	10^9	G
tera	10^{12}	T
peta	10^{15}	P
exa	10^{18}	E

1 petajoule = 10^{15} joules.

Approximate Conversion Factors

1 cubic metre	contains	6.3 barrels 35.3 cubic feet
1 petajoule	"	950 billion British thermal units (Btu)
1 cubic metre of natural gas	"	38 megajoules of energy
1 petajoule of natural gas	"	0.95 billion cubic feet (bcf)
1 cubic metre of crude oil	"	38 gigajoules of energy
1 kilowatt hour of electricity	"	3.6 megajoules of energy
1 tonne of coal	"	24 gigajoules of energy